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Transcript Exhibit(s)

Docket #(s): E-01750A-11-0136

Exhibit # : MEC2 - MEC12, S1 - S7

Part 2 of 3

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
MEC-2
ADMITTED

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01750A-11-0136 **NOTICE OF FILING OF SUPPLEMENTAL DIRECT TESTIMONY AND SCHEDULES WITH CALENDAR YEAR 2010 DATA**

Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative") by and through undersigned counsel, gives notice of the filing of Supplemental Direct Testimony of Michael W. Searcy and supporting Supplemental Schedules with calendar year 2010 data. This supplemental filing is being made in response to Commission's Staff request during the initial sufficiency review period. The Cooperative is making the filing in an effort to facilitate and expedite the processing of its Application for an adjustment in rates. Mr. Searcy's Supplemental Direct Testimony and supporting Supplemental Schedules accompany this Notice as Attachment 4. Attachments 1 through 3 accompanied Mohave's initial Application filed March 30, 2011.

RESPECTFULLY SUBMITTED this 27th day of May, 2011.

CURTIS, GOODWIN, SULLIVAN,
UDALL & SCHWAB, P.L.C.

By: ______________________
Michael A. Curtis
William P. Sullivan
Melissa A. Parham
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Attorneys for Mohave Electric
Cooperative, Incorporated

PROOF OF AND CERTIFICATE OF MAILING

I hereby certify that on this 27th day of May, 2011, I caused the foregoing document to be served on the Arizona Corporation Commission by delivering the original and thirteen (13) copies of the above to:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Mary Walker

1234\-18-8\Pleadings\Notice of Filing Supplemental Direct with 2010 data

ATTACHMENT 4

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No.E-01750A-11-0136

SUPPLEMENTAL DIRECT TESTIMONY OF

MICHAEL W. SEARCY

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

May 27, 2011

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DIRECT TESTIMONY OF

MICHAEL W. SEARCY

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

SUMMARY OF SUPPLEMENTAL DIRECT TESTIMONY

Mr. Searcy is a Managing Consultant with C.H. Guernsey & Company. He provides foundation for and explains Supplemental Sections A through R submitted to provide calendar year 2010 data, with some nominal adjustments, in support of Mohave Electric Cooperative, Incorporated's ("Mohave" or the "Cooperative") request for an adjustment in rates and charges. His supplemental direct testimony specifically discusses the calendar year 2010 data set forth in the supplemental schedules requested by Commission Staff, including:

1. Mohave's 2010 financial income statement with only revenue and power cost adjustments as shown in Supplemental Sections A, C, M and N;
2. Original Cost and Fair Value Rate Base based on 2010 data as set forth in Supplemental Section B;
3. 2010 Long term debt and monthly Operating TIER as set forth in Supplemental Sections D and E;
4. 2010 customer counts, usage data and adjustments as set forth in Supplemental Section F; and
5. Comparison of existing and proposed rates based upon 2010 billing determinants as set forth in Supplemental Sections H, K and R.

Mr. Searcy also discusses how the 2010 data demonstrates that the adjusted 2009 test year is still representative of Mohave's current operations and an appropriate base upon which to establish rates and charges for the Cooperative.

INTRODUCTION

Q. Please state your name, your employer and your position.

A. My name is Michael W. Searcy and I am employed by C. H. Guernsey & Company. My current position is Managing Consultant. My consulting activities include retail rate and financial analysis on behalf of clients. Information related to my address, educational background and work experience, and a copy of my resume, is included in my testimony related to the original rate filing.

Q. On whose behalf are you testifying in this matter?

A. I am appearing on behalf of Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative").

Q. Have you previously submitted testimony in this proceeding?

A. I prepared direct testimony in support of Mohave's Application for an adjustment in rates based upon a test year ending December 31, 2009. That testimony and supporting schedules accompanied the Cooperative's rate application filed March 30, 2011 (the "Application" or "original filing") as Attachment 3.

PURPOSE OF TESTIMONY

Q. What is the purpose of your supplemental direct testimony?

A. In the course of reviewing Mohave's Application to modify its rates and charges for sufficiency, Commission Staff requested supplemental information based upon the 2010 calendar year. In order to avoid disputes and facilitate the prompt and efficient processing of its Application, Mohave agreed to file specific Supplemental Schedules based on Mohave's calendar year 2010 operations, including:

1. The limited information required by Arizona Administrative Code ("A.A.C.") R14-2-103(B)(3) dealing with rate filings of electric distribution cooperatives (e.g., Supplemental Schedules A, C, D, E and M),
2. Supplemental Schedules showing the impact of 2010 billing determinants (e.g., Supplemental Sections F, H, K and R), excluding Cost of Service schedules (e.g., Sections G, I and J), and

3. Supplemental Schedules showing the impact of 2010 data on the calculation of base fuel costs and purchased power cost adjustor revenues (e.g., Supplemental Sections F and N).

My supplemental direct testimony and the Supplemental Schedules to which I am testifying are included with Mohave's Supplemental filing as Attachment 4. All Supplemental Schedules included in Attachment 4 are numbered based on the original rate filing numbering scheme, but with the word "Supplemental" preceding them. This numbering format is followed to allow the Commission to more readily compare the original and 2010 schedules and to avoid confusion.

My supplemental direct testimony provides the foundation for all the Supplemental Schedules being submitted by Mohave, discusses the data contained therein, and that the 2010 supplemental data serves to verify that the adjusted 2009 test year is representative of current operations and is not stale.

Q. Were the schedules contained in Sections A through L and Sections N, O and R included in Attachment 4 prepared by you or under your supervision?

A. Yes.

Q. Who supplied the data used in developing the Sections and schedules you are sponsoring?

A. All data was supplied by Mohave.

Q. Please explain where the information required by A.A.C. R14-2-103 can be found in Attachment 4.

A. The following table identifies where the data required by A.A.C. R14-2-103 can be located in this rate filing:

Provision	Data	Location
B.3.a	RUS Form 7	Supplemental Section M
B.3.a	Most Recent (2010) Audit	Supplemental Section M
B.3.c	Bill Count Data	
	Bill Frequency Summary	Supplemental Schedule H-5.0,
	2010 Proof of Revenue – Existing Rates	Supplemental Schedule F-4.0,

	2010 Proof of Revenue – Proposed Rates	Supplemental Schedule N-1.0
	Detailed Bill Frequency Data	*Supplemental* Schedule K-1.0,
B.3.d	Summary of Change in Revenue	Supplemental Schedule H-1.0
	Billing Comparisons	Supplemental Schedules H-4.0 -H-4.8
B.3.e	Long -Term Debt	
	2010 Long-Term Debt	Supplemental Schedule D-5.0
B.3.f	Summary of TIER	Supplemental Schedule E-2.0

Q. What additional supplemental schedules providing 2010 data are you sponsoring in your supplemental direct testimony?

A. A listing of all Supplemental Schedules is provided in the Table of Contents preceding the schedules included in Attachment 4. Those schedules indicating they are intentionally left blank reflect schedules for which Staff did not request supplemental 2010 data.

Q. What is the test year in this proceeding?

A. Mohave submitted its Application based upon the test year ending December 31, 2009. All information included in the supplemental filing is based on the calendar year ending December 31, 2010. As discussed in more detail in my supplemental direct testimony, the 2010 data demonstrates that the adjusted 2009 test year used by Mohave remains representative of the Cooperative's current operations.

FINANCIAL ADJUSTMENTS

Q. Please explain Supplemental Schedule A-1.0.

A. Supplemental Schedule A-1.0 is the Income Statement for the 2010 calendar year showing:

1. Actual 2010 Calendar Year (ending December 31, 2010),
2. Adjustments to the 2010 Calendar Year (Revenue and power cost only),
3. Adjusted 2010 Calendar Year (Actual Calendar Year Plus Adjustments),

4. Requested Revenue Change (based upon proposed Tariffs set forth in Section P of Attachment 3 to the Application), and

5. Adjusted Calendar Year With Rate Change (Adjusted Calendar Year Plus Requested Revenue Change).

Adjustments described below correspond to adjustment amounts shown in the "Adjustments" column on Supplemental Schedule A-1.0.

Column (a) is information taken directly from Mohave's 2010 Form 7 based upon audited data. The 2010 Form 7 is included in Supplemental Section M of Attachment 4. The 2009 Form 7 was provided in Section M of Attachment 3 to the Application.

Q: Please explain adjustments shown on Supplemental Schedule A-1.0.

A. Adjustments are shown on Supplemental Schedules A-4.0 and A-5.0.

<u>Operating Revenue (Supplemental Schedule A-4.0)</u>.

Calculation of revenue shown on this schedule is developed on Supplemental Schedule F-4.0. This schedule calculates revenue by applying existing rates to 2010 billing units. 2010 Customer and kWh billing units are found on Supplemental Schedules F-1.0 through F-2.0. 2010 Demand billing units are found in Supplemental Schedules R-1.0 through R-3.1.

<u>Base Revenue (Supplemental Schedules F-4.0, F-3.0 and F-4.1)</u>.

One of Mohave's two Substation Level service customers was billed under a special contract rate in 2010. The contract has now ended and will not be renewed. Adjusted 2010 base revenue and PPCA revenue for this customer, therefore, have been calculated under the standard LC&I rate as shown on Supplemental Schedule F-4.0. A similar adjustment was made to the 2009 test year. (*See,* Schedule F-4.0 in Attachment 3 to the Application).

Consistent with Mohave's Application, an adjustment to base revenue related to third-party sales (TPS) revenue has been made. The nature of the adjustment is explained in the direct testimony of Mr. Stover (Attachment 2 to the Application). As shown on Supplemental Schedule F-3.0, 2010 TPS revenue was $1,826,810 as compared to $630,817 in 2009. (See, Schedule F-3.0 to Attachment 3). The revenues for TPS were adjusted to $3,698,667, as developed on Supplemental Schedule F-4.1.

The same level of adjusted TPS revenues was reflected in the adjusted 2009 test year as developed on Schedule F-4.1 in Attachment 3 to the Application.

Adjustments from all causes to base 2010 calendar year revenue result in an increase of $2,423,662, as shown on Supplemental Schedules F-4.0, A-1.0 and A-4.0. In contrast, the Cooperative had adjusted base test year 2009 revenue by $3,655,648 as shown on Schedules F-4.0, A-1.0 and A-4.0 in Attachment 3 to the Application. The $1,231,986 reduction in the amount of base revenue increase is primarily due to the $1,195,993 increase in actual TPS base revenue in calendar year 2010 over the 2009 test year TPS base revenue.

Billing Units (Schedules F-1.0 – F-4.0).

Mohave did not show material growth in customers during 2009 or 2010. Therefore, no adjustment to either the 2010 calendar year or 2009 test year data was made to "year-end" customers. Consistent with the adjustments made to the 2009 test year (as described at page 10, lines 1-17 of my direct testimony included in Attachment 3 to the Application), customer counts were normalized as shown on Supplemental Schedule F-1.2 and to TPS usage, as described above, and as shown on Supplemental Schedule F-7.1.

Purchased Power Cost Adjustment Revenue (Supplemental Schedules F-4.0 and F-5.0).

A revenue adjustment was made to restate PPCA revenue based on adjusted 2010 power cost (Supplemental Schedule F-5.0). Total adjusted 2010 power cost excluding TPS was used for the calculations along with total adjusted 2010 kWh sales excluding TPS and lighting customers. As discussed at page 10, lines 22-25 of my direct testimony (Attachment 3 of the Application) lighting customers kWh usage is not individually metered and historically Mohave has not collected PPCA revenue from this class of customer. On a going forward basis, Mohave will recover PPCA revenue from lighting customers based upon imputed kWh usage for the type of lighting involved.

The restatement of PPCA revenue decreases 2010 PPCA revenue by $677,317, in contrast to a $3,639,180 decrease of 2009 test year PPCA revenue. In 2010, Mohave recorded "Over/Under Revenue" of ($3,946,026). This was "zeroed out" as a part of PPCA recalculation. The total adjustment related to 2010 calendar year PPCA revenue results in an increase of $3,268,709 ($3,946,026 - $677,317) as shown on Supplemental Schedules F-4.0, A-1.0 and A-4.0. The total adjustment related to 2009 test year PPCA revenue resulted in an increase of $2,828,653 ($6,467,833 - $3,639,180) as shown on Schedules F-4.0, A-1.0 and A-4.0 in Attachment 3 to the Application.

Other Revenue (Supplemental Schedule C-4.0).

2010 "Other" revenue was reduced by $142,170, as shown on Supplemental Schedule C-4.0. Consistent with the adjustments made to the 2009 test year, three items were eliminated: Power Displacement Agreement Revenue (Acct 451), Device Rental Revenue (Acct 454) and Other Electric Revenues (Acct 456). As explained in my direct testimony at page 11, lines 5-9, these items are related to services provided by the Cooperative to third parties under contracts that have terminated. Account 454 - Pole Attachment Rental was increased to annualize revenue due to an increase in the pole attachment revenue paid to Mohave. The total adjustment related to 2009 test year "Other" revenue was a reduction of $118,189, as shown on Schedules C-4.0, A-4.0 and A-1.0 in Attachment 3 to the Application.

Summary of Changes to Total Revenue (Supplemental Schedule A-1.0).

The total adjustment to revenue based on 2010 billing units, is an increase of $5,550,201, as shown on Supplemental Schedules F-4.0, A-1.0 and A-4.0. This compares to an increase in revenue of $6,366,112 in the original filing based on 2009 billing units. The 1.2 million dollar reduction in the revenue adjustment between the 2009 and 2010 is substantially offset by the reduction in purchased power costs discussed next.

Purchased Power (Supplemental Schedule A-5.0).

The net increase to 2010 power cost is $5,508,614, as shown on Supplemental Schedules F-7.2, A-1.0 and A-5.0. This compares to an increase of $6,190,975 to 2009 test year power costs set forth in Schedules F-7.2, A-1.0 and A-5.0 in Attachment 3 of the Application. Adjusted 2010 purchased power expense was developed on Supplemental Schedules F-7.0 through F-7.2 and summarized on Schedule A-5.0. TPS power cost was adjusted to match estimated sales and projected TPS unit power cost as developed in the Application at Schedules F-7.0 through F-7.2 of Attachment 3. For the remainder of the system, wholesale rates for

2011 were applied to adjusted 2010 billing units. Adjusted wholesale fuel cost used in the calculation was developed by taking the actual monthly 2010 wholesale fuel factors and correcting them based on the fuel cost rebasing included in the power supplier's most recent rate filing.

Consistent with the Application, Mohave proposes development of a property tax adjustment (PTA) to reflect changes, up or down, in the overall property taxes it is paying to governmental bodies, as compared to the level of property taxes included in the adjusted 2009 test year. Supplemental Schedule N-2.2 shows that the amount of change between the property tax included in the adjusted 2009 test year and the actual 2010 property tax was only $3,314. This was not considered to be a material amount, and no adjustment to revenue was made as a part of this 2010 supplemental analysis.

No adjustments were made to the 2010 Calendar Year Income Statement other than those to revenue and power cost as discussed above.

Q. Are the adjustments to 2010 revenue and power cost related to activities that are known, measurable and of a continuing nature?

A. Yes.

Q. What is the overall impact of the adjustments made to 2010?

A. The overall impact of the revenue and expense adjustments is to increase 2010 operating margins by $41,587, as reflected in column (b) of Supplemental Schedule A-1.0.

As shown on Schedule A-1.0 Attachment 3 to the Application, the adjusted 2009 test year gross income (revenue - power cost) is $14,276,228 ($78,740,725 - $64,464,497). As a part of this review of 2010 data, the adjusted 2010 gross income is $14,265,329 ($76,068,006 - $61,802,677) – a reduction of gross revenue from adjusted 2009 test year to adjusted 2010 calendar year of just $10,899.

The adjusted 2010 Operating TIER is 0.21, the RUS OTIER is 0.23 and the CFC DSC is 0.83. As reflected on Schedule A-1.0 in Attachment 3 to the Application, the adjusted 2009 test year Operating TIER is 0.56, the RUS OTIER is 0.57 and the CFC DSC is 1.06.

In both 2010 and 2009, the coverage ratios are insufficient and additional revenue is needed to improve the coverage ratios.

Q. Would using the adjusted 2010 calendar year discussed above justify a greater or lesser increase in revenues than use of the adjusted 2009 test year?

A. The lower coverage ratios in 2010 would justify a greater increase in revenues than requested by Mohave's Application.

Q. Is Mohave requesting a greater increase to reflect the reduced financial coverage based upon the 2010 calendar year data?

A. No. The Cooperative is requesting the same rates as proposed in its Application.

Q. What is the impact on the income statement of applying the proposed rates to 2010 billing units?

A. Supplemental Schedule A-1.0 shows in column (e) the impact on revenue of applying the proposed rates to 2010 billing units. There is an increase in revenue of $2,994,231. As reflected on Schedule A-1.0 of Attachment 3 of the Application, the amount of revenue change resulting from applying the proposed rates to 2009 billing units was $2,980,757. The difference in rate change between the 2009 test year and calendar year 2010 ($13,474) is minimal.

Supplemental Schedules N-1.0, N-2.1, and N-3.0 show development of proposed revenue applied on 2010 billing units. A summary of proposed revenue applied on 2010 billing units is shown on Supplemental Schedule H-1.0.

The adjusted 2010 Operating TIER with the proposed rate change is 1.59, the RUS OTIER is 1.61 and the CFC DSC is 1.62. These coverage ratios are less than the ratios for the adjusted 2009 test year with proposed rate change as reflected on Schedule A-1.0 of Attachment 3 to the Application (Adjusted Operating TIER with new rates of 1.92, RUS OTIER of 1.94 and CFC DSC of 1.85), but in each case they exceed the minimum requirements of Mohave's lenders.

RATE BASE

Q. What is the Fair Value Rate Base developed in the adjusted 2010 calendar year?

A. The adjusted calendar year 2010 original cost rate base of $48,083,871 as of December 31, 2010, reflected on Supplemental Schedule B-1.0, is the Fair Value Rate Base ("FVRB") for ratemaking purposes. As was the case in the application based upon a test year ending 12/31/2009, this amount includes substantial reductions for consumer deposits, consumer construction advances and consumer energy prepayments. Cash working capital has also been removed.

COST OF SERVICE STUDY

Q. Is Mohave providing supplemental calendar year 2010 data related to the Cost of Service Study it filed with the Application as Schedule G and supporting schedules?

A. No. Mohave and the Commission Staff agreed that the originally filed cost of service study based upon the 2009 test year data will be utilized for processing Mohave's Application, subject any necessary adjustments.

RATE DESIGN AND IMPACT ON CUSTOMERS

Q. Is Mohave proposing any revisions to the rates and rate designs reflected in its Application as a result of the supplemental 2010 data?

A. No. The calculations developed for the rate change adjustment to the 2010 calendar year simply apply the rates and charges proposed in the Application to 2010 billing units.

Q. What are the proposed revenue changes for each class using 2010 billing units?

A. The revenue change resulting from Mohave's proposed rates for each rate class under 2010 billing units is shown on Supplemental Schedule H-1.0. Proposed PPCA base cost used in the calculation of the proposed PPCA revenue is shown on Supplemental Schedules N-2.0 and 2.1. Note, the base cost of power per kWh included in rates ("Authorized Base Cost") is the base cost developed on the adjusted 2009 test year of $0.091183.

Q. Why do some of the Time-of-Use rate classes in particular show different percentage increases based on 2010 usage as compared to the 2009 test year?

A. Mohave's small commercial and large commercial and industrial rate time-of-use rate classes have very few customers. In 2009, there were four customers in the small commercial TOU class and only one in the secondary LC&I TOU class. In 2010, there were eight customers in the small commercial TOU class and three in the secondary LC&I class. Customers are free to move to and from the TOU rate classes. While the changes in dollar amount difference of the 2009 and 2010 increase are relatively small, on a percentage basis, the changes appear to be high.

In addition, as discussed in the Mohave's Application in my direct testimony at page 27, line 26 through page 28, line 8, existing time-of-use rates for all demand billed time-of-use rate classes include only a single demand charge, based on usage during the on-peak window. While the majority of the demand cost included in the demand charge is related to purchased power capacity cost, the Cooperative should recover at least a portion of its own capacity-related cost of providing service through the demand charge. An unintended result of the existing rate design is to allow customers who can shift usage out of the on-peak period to avoid, not only purchased power capacity cost, but also the Cooperative's recovery of its own capacity-related wires cost.

In the proposed rate designs, Mohave separates its time-of-use demand charge into an on-peak demand charge to recover purchased power capacity cost, which the customer can avoid by shifting usage outside of the on-peak windows; and a monthly non-coincident peak (NCP) demand charge to recover a portion of the Cooperative's own wires cost of providing service and measured in the same manner as the demand is applied to the standard irrigation customers.

Q. Why is the percentage increase for lighting less than originally proposed?

A. As I already indicated, the lighting class has historically not been billed PPCA due to a lack of billed kWh units. On a going forward basis, Mohave proposes to impute a standard kWh based upon the lighting fixture involved and to bill lighting customers a monthly PPCA under proposed rates. Since there is a small reduction in the adjusted 2010 PPCA factor as compared to the 2009 adjusted test year, including collection of PPCA in the proposed rates results in a smaller percentage increase.

Q. Have all of the rate designs been revised to reflect proposed base power cost in the wholesale power cost adjustment?

A. Yes. Each proposed retail rate design reflects the proposed wholesale power cost adjustment calculated using the base power cost of $0.091183 per kWh sold, as shown on Supplemental Schedules N-2.0 and N-2.1. Since the adjusted 2010 cost of power at $0.089333 per kWh is slightly less than the 2009 adjusted test year power cost per kWh, the PPCA factor under proposed rates to apply to 2010 billing units is ($0.00185) per kWh. As stated earlier, there is no proposed change to the base cost of power used to calculate PPCA as proposed in the Application.

Q. Does Mohave propose changes to its service charges or fees?

A. Yes. These changes are reflected in the Application. Supplemental Schedule N-3.0 shows proposed changes to existing service charges or fees, also called "other revenue." The 2010 occurrences of these charges or fees were used to calculate the adjusted 2010 "other revenue."

Total additional revenue proposed from "other revenue" is $256,647 based upon 2010 data as compared to $274,546 of additional "other revenue" based upon the 2009 test year – a reduction of $17,899 in 2010 as compared to the 2009 test year.

TARIFF CHANGES

Q. After reviewing the supplemental 2010 data, does Mohave propose changes to its rate tariffs beyond those originally reflected in the Application?

A. No. Mohave understands that its proposed rates would not have produced the level of revenues it is requesting during 2010 due to a decrease in kWhs sold. However, by implementing a rate design that more closely reflects cost incurrence, the bulk of the lost sales are set off by reduced power costs.

SUMMARY OF IMPACT OF 2010 DATA

Q. Please summarize the differences between the 2009 test year used by Mohave in its Application and the adjusted 2010 calendar year data.

A. As indicated above, the 2010 calendar year data as adjusted for the new wholesale power rate, new wholesale billing units, and the accompanying changes on PPCA revenue result in total gross income (revenue less power cost) that is extremely similar to the gross income shown in the adjusted 2009 test year upon which Mohave's Application is based.

As shown on Supplemental Schedule A-1.0, 2010 operating expenses excluding cost of power were $15,974,336 ($75,456,285 + $2,320,728 - $61,802,677). Actual 2009 test year operating expenses excluding cost of power as shown on Schedule A-1.0 in the original filing were $15,594,333 ($71,532,793 + $2,335,062 - $58,273,522). This difference of $380,003 is only 0.5% different from the actual 2009 total operating expense level of $73,867,855 ($71,532,793 + 2,335,062). In the 2009 test year, the operating margin was ($1,493,242). Calendar year 2010 showed an operating margin of ($1,750,594).

Q. Does the adjusted 2010 calendar year data serve to validate the reasonableness of Mohave's use of a 2009 test year?

A. Yes. The similarities in usage, gross income and expenses indicate that the 2009 adjusted test year expense levels used to determine the revenue requirement in the Cooperative's Application continue to be representative of expense levels the Cooperative should recover through its rates and gross income. Calendar year 2009 continues to represent data that can be confidently used to develop adjusted test year expense levels (including power cost), adjusted and proposed test year revenue levels, a sound cost of service study and rate designs.

We prepared Supplemental Schedule A-1.1 comparing the 2009 test year with revenues from Mohave's proposed rates to the adjusted 2010 calendar year with revenues from Mohave's proposed rates. The bottom line is that the supplemental 2010 data tends to support a somewhat greater revenue increase than Mohave is proposing. However, the level of increase does not warrant the time and cost associated with development of an entirely new test year.

Q. Does this conclude your testimony?

A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

Bullhead City, Arizona

SUPPLEMENTAL DATA REQUESTED FOR 2010

May 2011

C. H. GUERNSEY & COMPANY
Engineers • Architects • Consultants
Oklahoma City, Oklahoma

MOHAVE ELECTRIC COOPERATIVE, INC.

SUPPLEMENTAL 2010 DATA REQUESTED

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MOHAVE ELECTRIC COOPERATIVE, INC.

Key to Filing – Supplemental Data

Information in the format set forth in AAC R14-2-103(B)(3)

For a calendar year ending 12/31/10

1. **Form 7 for the 12 months ending 12/31/10**

   Supplemental Section M

2. **Bill count, using 2010 billing data, for each rate schedule**

   Summary of bill frequency – Supplemental Schedule H-5.0

   Individual detailed rate class bill frequency data - Supplemental Section K

   Adjusted revenue with 2010 billing units - Supplemental Schedule F-4.0

   Proposed revenue with 2010 billing units – Supplemental Schedule N-1.0

3. **Comparison of revenues by customer classification at present and proposed rates, using 2010 billing**

   Supplemental Schedule H-1.0

4. **Schedule listing long term debt obligations as of 12/31/10**

   Supplemental Schedule D-5.0

5. **Monthly schedule of TIER for the 12 month periods ending 12/31/10, 12/31/09 and projected for 12/31/12**

   Supplemental Schedule E-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

Key to Filing – Supplemental Data

1. **2010 OCLD rate base**

   Supplemental Section B

2. **Development of base revenue under proposed rates with 2010 data**

   Supplemental Schedules N-1.0 through N-1.2

3. **Development of PPCA, PTA and Other revenue with 2010 data**

   Supplemental Schedules N-2.0 through N-3.0

4. **Supporting schedules to support calculating the base fuel cost using 2010 data**

   For adjusted 2010 power cost – Supplemental Schedule F-7.0

   For adjusted 2010 PPCA revenue – Supplemental Schedule F-5.0

   For proposed PPCA revenue using 2010 data – Supplemental Schedules N-2.0 through N-2.1

MOHAVE ELECTRIC COOPERATIVE, INC.

Key to Filing – Supplemental Data

6. **Key to electronic files**

Supplemental Sections A – E	See Electronic File **Financials_2010.xlsx**
Supplemental Section F	See Electronic File **Usage_2010.xlsx**
Supplemental Schedule H-1.0	See Electronic File **Usage_2010.xlsx**
Supplemental Schedules H-4.0–4.8	See Electronic File **Compare_2010.xlsx**
Supplemental Schedules H-5.0-H-5.1	See Electronic File **Usage_2010.xlsx**
Supplemental Section N	See Electronic File **Usage_2010.xlsx**

SUPPLEMENTAL SCHEDULE A

MOHAVE ELECTRIC COOPERATIVE, INC.

INCOME STATEMENT - SUPPLEMENTAL DATA
DECEMBER 31, 2010

	Calendar Year 12/31/2010 (a)	Revenue & Power Cost Adjustments (b)	Adjusted 12/31/2010 (c)	Proposed Rate Change (d)	Adjusted 12/31/2010 with Rate Change (e)
Operating Revenues					
Base Revenue	$ 57,532,211	$ 2,423,662	$ 59,955,873	$ 19,450,152	$ 79,406,025
PPCA	16,182,551	(677,317)	15,505,234	(16,712,569)	(1,207,335)
PPCA (Over)/Under	(3,946,026)	3,946,026	0	0	0
Other	749,069	(142,170)	606,899	256,648	863,547
Total	$ 70,517,805	$ 5,550,201	$ 76,068,006	$ 2,994,231	$ 79,062,237
Operating Expenses					
Purchased Power	$ 56,294,063	$ 5,508,614	$ 61,802,677	$	$ 61,802,677
SubTransmission O&M	169,400		169,400		169,400
Distribution-Operations	2,773,698		2,773,698		2,773,698
Distribution-Maintenance	1,194,657		1,194,657		1,194,657
Consumer Accounting	2,227,246		2,227,246		2,227,246
Customer Service	196,226		196,226		196,226
Sales	96,252		96,252		96,252
Administrative & General	4,756,463		4,756,463		4,756,463
Depreciation	2,239,666		2,239,666		2,239,666
Tax	0		0		0
Total	$ 69,947,671	$ 5,508,614	$ 75,456,285	$ 0	$ 75,456,285
Return	$ 570,134	$ 41,587	$ 611,721	$ 2,994,231	$ 3,605,952
Interest & Other Deductions					
Interest L-T Debt	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308
Amortize RUS Gain	*0*		0		0
Interest-Other	142,396		142,396		142,396
Other Deductions	17,024		17,024		17,024
Total	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728
Operating Margin	$ (1,750,594)	$ 41,587	$ (1,709,007)	$ 2,994,231	$ 1,285,224
Non-Operating Margins					
Interest Income	$ *410,049*	$	$ 410,049	$	$ 410,049
Gain(Loss) Equity Investments	110,369		110,369		110,369
Other Margins	(32,307)		(32,307)		(32,307)
G&T Capital Credits	3,509,969		3,509,969		3,509,969
Other Capital Credits	107,687		107,687		107,687
Total	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767
Net Margins	$ 2,355,173	$ 41,587	$ 2,396,760	$ 2,994,231	$ 5,390,991
Operating TIER	0.19		0.21		1.59
RUS OTIER	0.21		0.23		1.61
Net TIER Excl Capital Credits	0.42		0.44		1.82
Net TIER	2.09		2.11		3.49
CFC DSC	0.82		0.83		1.82
Rate of Return	1.09%		1.27%		7.50%
Rate Base	$ 52,531,989	$ (4,448,118)	$ 48,083,871	$ 0	$ 48,083,871
Principal Payments	1,624,749		1,624,749		1,624,749
Percent Change					3.94%

Adjustments to Revenue - Sup Schedule A-4.0
Adjustments to Power Cost - Sup Schedule A-5.0
Adjustments to Rate Base - Sup Schedule B-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARE ADJUSTED 2010 CALENDAR YEAR TO ADJUSTED 2009 TEST YEAR
DECEMBER 31, 2010

	Adjusted 2009 TY w/ Rate Change	Adjusted 2010 w/ Rate Change	Difference
Operating Revenues			
Base Revenue	$ 80,844,622	$ 79,406,025	$ (1,438,597)
PPCA	-	(1,207,335)	(1,207,335)
PPCA (Over)/Under	-	-	-
Other	876,860	863,547	(13,313)
Total	$ 81,721,482	$ 79,062,237	$ (2,659,245)
Operating Expenses			
Purchased Power	$ 64,464,497	$ 61,802,677	$ (2,661,820)
SubTransmission O&M	134,577	169,400	34,823
Distribution-Operations	1,685,212	2,773,698	1,088,486
Distribution-Maintenance	1,397,001	1,194,657	(202,344)
Consumer Accounting	2,172,301	2,227,246	54,945
Customer Service	43,056	196,226	153,170
Sales	71,499	96,252	24,753
Administrative & General	4,136,181	4,756,463	620,282
Depreciation	2,293,219	2,239,666	(53,553)
Tax	1,001,834	-	(1,001,834)
Total	$ 77,399,377	$ 75,456,285	$ (1,943,092)
Return	$ 4,322,105	$ 3,605,952	$ (716,153)
Interest & Other Deductions			
Interest L-T Debt	$ 2,180,403	$ 2,161,308	$ (19,095)
Amortize RUS Gain	-	-	-
Interest-Other	118,932	142,396	23,464
Other Deductions	7,397	17,024	9,627
Total	$ 2,306,732	$ 2,320,728	$ 13,996
Operating Margin	$ 2,015,373	$ 1,285,224	$ (730,149)
Non-Operating Margins			
Interest Income	$ 499,868	$ 410,049	$ (89,819)
Gain(Loss) Equity Investments	110,369	110,369	-
Other Margins	4,256	(32,307)	(36,563)
G&T Capital Credits	2,779,792	3,509,969	730,177
Other Capital Credits	158,148	107,687	(50,461)
Total	$ 3,552,433	$ 4,105,767	$ 553,334
Net Margins	$ 5,567,806	$ 5,390,991	$ (176,815)
Operating TIER	1.92	1.59	-0.33
RUS OTIER	1.94	1.61	-0.33
Net TIER Excl Capital Credits	2.21	1.82	-0.39
Net TIER	3.55	3.49	-0.06
CFC DSC	1.85	1.62	-0.23
Rate of Return	9.17%	7.50%	-1.67%
Rate Base	$ 47,128,697	48,083,871	955,174
Percent Change	3.79%	3.94%	0.15%

Supplemental Schedules A-2.0 through A-3.0

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MOHAVE ELECTRIC COOPERATIVE, INC.

REVENUE

	Calendar Year 12/31/2010	Revenue & Power Cost Adjustments	Adjusted 12/31/2010
Base Revenue	$ 57,532,211	$ 2,423,662	$ 59,955,873
PPCA	16,182,551	$ (677,317)	15,505,234
PPCA (Over)/Under	(3,946,026)	$ 3,946,026	0
Total Electric Revenue	$ 69,768,736	$ 5,692,371	$ 75,461,107
Other Revenue	$ 749,069	$ (142,170)	$ 606,899
Total	$ 70,517,805	$ 5,550,201	$ 76,068,006

See Supplemental Schedules F-4.0, F-4.1, F-5.0 and C-4.0

MOHAVE ELECTRIC COOPERATIVE, INC.

PURCHASED POWER

		Calendar Year 12/31/2010	Revenue & Power Cost Adjustments	Adjusted 12/31/2010
555.00	Purchased Power	$ 53,861,669	$ 4,146,305	$ 58,007,974
	Off System Sales (TPS)	1,860,671	1,362,309	3,222,980
		55,722,340	5,508,614	61,230,954
557.00	Pur Pwr Other	571,723	0	571,723
Total		$ 56,294,063	$ 5,508,614	$ 61,802,677

***** See Supplemental Schedule F-7.0 - F-7.2***

Supplemental Schedules A-6.0 through A-16.0

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SUPPLEMENTAL SCHEDULE B

MOHAVE ELECTRIC COOPERATIVE, INC.

RATE BASE - SUPPLEMENTAL INFORMATION
DECEMBER 31, 2010

	Calendar Year 12/31/2010 (a)	Revenue & Power Cost Adjustments (b)	Adjusted 12/31/2010 (c)	Proposed Rate Change (d)	Adjusted 12/31/2010 with Rate Change (e)
Plant in Service	$ 88,890,934	$	$ 88,890,934	$	$ 88,890,934
CWIP	3,021,375	(3,021,375)	0		0
Total Utility Plant	$ 91,912,309	$ (3,021,375)	$ 88,890,934	$ 0	$ 88,890,934
Accumulated Depreciation	(35,708,314)		(35,708,314)		(35,708,314)
Net Utility Plant	$ 56,203,995	$ (3,021,375)	$ 53,182,620	$ 0	$ 53,182,620
Materials & Supplies	$ 2,087,854	$ 0	$ 2,087,854	$ 0	$ 2,087,854
Prepayments	1,227,991	0	1,227,991	0	1,227,991
Cash Working Capital	1,426,743	(1,426,743)	0	0	0
Consumer Deposits	(2,494,774)	0	(2,494,774)	0	(2,494,774)
Consumer Construction Advances	(4,596,854)	0	(4,596,854)	0	(4,596,854)
Consumer Energy Prepayments	(1,322,966)	0	(1,322,966)	0	(1,322,966)
Working Capital & Deductions	$ (3,672,006)	$ (1,426,743)	$ (5,098,749)	$ 0	$ (5,098,749)
Total Rate Base	$ 52,531,989	$ (4,448,118)	$ 48,083,871	$ 0	$ 48,083,871
Operating Revenues	$ 70,517,805	$ 5,550,201	$ 76,068,006	$ 2,994,231	$ 79,062,237
Operating Expenses	69,947,671	5,508,614	75,456,285	0	75,456,285
Return	$ 570,134	$ 41,587	$ 611,721	$ 2,994,231	$ 3,605,952
Rate of Return	1.09%		1.27%		7.50%

Supplemental Schedules B-2.0 through B-3.0

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SUPPLEMENTAL SCHEDULE C

Supplemental Schedules C-1.0 through C-3.0

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Schedules C-1.0 through C-3.0

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MOHAVE ELECTRIC COOPERATIVE, INC.

OTHER REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

Account	Description	Calendar Year 12/31/2010	Revenue & Power Cost Adjustments	Adjusted 12/31/2010
451.00	Reconnect Fees	$ 69,750.00	$	$ 69,750.00
451.00	Connect Fees	280,900.00		280,900.00
451.00	Other Revenue	9,883.17		9,883.17
451.00	Power Displacement Agreement *	117,546.00	-117,546.00	0.00
451.00	Miscellaneous	(35.33)		-35.33
451.11	Power/Revenue Loss	9,052.12		9,052.12
454.00	Pole Attachment Rental **	222,768.04	2,375.96	225,144.00
454.00	Device Rental *	12,000.00	-12,000.00	0.00
456.00	Other Electric Revenues *	15,000.00	-15,000.00	0.00
456.10	Returned Check Collection Charges	12,060.00		12,060.00
456.20	Meter Re-Read Charge	145.00		145.00
456.30	Meter Test Fees	0.00		0.00
	Total	$ 749,069.00	$ (142,170.04)	$ 606,898.96

See Also Supplemental Schedule N-3.0
**** Provided by Contract - will not continue in 2011 and beyond***
***** Contract changed April 2010 - New rate annualized***

Supplemental Schedules C-5.0 through C-6.0

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SUPPLEMENTAL SCHEDULE D

Supplemental Schedules D-1.0 through D-4.0

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MOHAVE ELECTRIC COOPERATIVE, INC.

LONG-TERM DEBT
AS OF DECEMBER 31, 2010

Note Number	Date of Issue	Term	Lender	Interest Rate	Original Amount	Unadvanced Amount	Principal Outstanding
14190	10/23/1980	35	RUS	2.0000%	$ 1,127,000.00	$	$ 215,299.00
14191	10/23/1980	35	RUS	2.0000%	473,000.00		97,454.47
Total RUS 2%					$ 1,600,000.00	$ 0.00	$ 312,753.47
1B160	11/21/1975	35	RUS	5.0000%	$ 167,000.00	$	$ 0.00
1B162	11/21/1975	35	RUS	5.0000%	167,000.00		0.00
1B170	6/17/1977	35	RUS	5.0000%	363,500.00		27,576.43
1B172	6/17/1977	35	RUS	5.0000%	363,500.00		27,576.43
1B180	1/23/1979	35	RUS	5.0000%	306,000.00		53,203.27
1B182	1/23/1979	35	RUS	5.0000%	306,000.00		53,203.27
1B200	5/9/1981	35	RUS	5.0000%	1,567,000.00		448,778.35
1B202	5/9/1981	35	RUS	5.0000%	1,567,000.00		448,778.35
Total RUS 5% Quarterly					$ 4,807,000.00	$ 0.00	$ 1,059,116.10
1B210	9/22/1983	35	RUS	5.0000%	$ 1,132,000.00	$	$ 447,867.93
1B212	9/22/1983	35	RUS	5.0000%	1,132,000.00		414,635.23
1A213	9/22/1983	35	RUS	5.0000%	84,000.00		34,848.28
1B220	9/29/1986	35	RUS	5.0000%	3,514,000.00		1,780,369.24
1A223	9/29/1986	35	RUS	5.0000%	3,514,000.00		1,833,116.22
1A230	1/19/1983	35	RUS	5.0000%	3,885,000.00		2,724,144.87
1A235	7/26/1994	35	RUS	5.0000%	3,476,000.00		2,437,355.95
1A238	3/31/1999	35	RUS	5.0000%	490,000.00		301,597.71
1B240	3/30/1998	35	RUS	5.2500%	2,217,500.00		1,736,509.10
1B245	4/13/1998	35	RUS	5.1200%	2,050,000.00		1,602,766.16
1B246	2/24/1999	35	RUS	5.0000%	167,500.00		131,538.37
Total RUS Monthly					$ 21,662,000.00	$ 0.00	$ 13,444,749.06
Total RUS Debt					$ 28,069,000.00	$ 0.00	$ 14,816,618.63

MOHAVE ELECTRIC COOPERATIVE, INC.

LONG-TERM DEBT
AS OF DECEMBER 31, 2010

Note Number	Date of Issue	Term	Lender	Interest Rate	Original Amount	Unadvanced Amount	Principal Outstanding
10001	4/26/2007	35	FFB	4.8120%	$ 12,926,000.00	$	$ 12,179,222.28
10002	6/4/2007	35	FFB	5.0530%	1,421,000.00		1,355,257.77
10003	11/9/2007	35	FFB	4.5870%	2,600,000.00		2,478,395.41
10004	8/21/2009	35	FFB	4.0060%	1,106,000.00		1,080,860.87
Total FFB					$ 18,053,000.00	$ 0.00	$ 17,093,736.33
9004	3/24/1976	35	CFC	7.4500%	$ 84,000.00	$	$ 0.00
9008	7/1/1977	35	CFC	5.8500%	312,000.00		29,975.82
9013	12/31/1978	35	CFC	5.7500%	262,000.00		56,846.23
9015	3/31/1981	35	CFC	5.9700%	1,414,000.00		494,395.07
9019	9/22/1983	35	CFC	5.8500%	1,021,000.00		442,690.54
9020	6/30/1986	35	CFC	6.2100%	3,170,526.00		1,848,901.76
9021	6/30/1997	35	CFC	8.7500%	3,505,263.00		2,700,646.08
Total CFC					$ 9,768,789.00	$ 0.00	$ 5,573,455.50
36346	1/3/1998	30	CoBank	7.2500%	$ 1,900,000.00	$	$ 1,656,995.98
Total Other Debt					$ 11,668,789.00	$ 0.00	$ 7,230,451.48
Total Long-Term Debt					$ 57,790,789.00	$ 0.00	$ 39,140,806.44

Supplemental Schedules D-6.0 through D-8.0

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SUPPLEMENTAL SCHEDULE E

Supplemental Schedule E-1.0

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MOHAVE ELECTRIC COOPERATIVE, INC.

MONTHLY OPERATING TIER COVERAGE

	Calendary Year 12/31/2010	Prior Year 12/31/2009	Projected 12/31/2012
January	0.52	1.59	1.76
February	0.24	0.14	1.76
March	-0.44	-0.10	1.76
April	0.45	-1.14	1.76
May	-0.68	-0.57	1.76
June	-0.42	0.55	1.76
July	1.51	2.23	1.76
August	3.83	2.92	1.76
September	3.73	2.11	1.76
October	-1.36	1.16	1.76
November	-1.52	-1.54	1.76
December	-3.48	-3.49	1.76
Annual	0.19	0.32	1.76

Operating TIER = (Operating Margins + Interest on LT Debt) / Interest on LT Debt

SUPPLEMENTAL SCHEDULE F

MOHAVE ELECTRIC COOPERATIVE, INC.

CONSUMERS BY RATE SCHEDULE - EXISTING
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total	Average
Residential	101	35,239	35,441	35,573	35,578	35,359	35,390	35,190	35,427	35,136	35,305	35,266	35,175	424,079	35,340
Residential - Seasonal	102	2	2	2	1	1	1	1	1	0	0	0	0	11	1
Residential - Net Metering	105	0	3	47	72	77	82	88	91	98	100	101	104	863	72
Res - Gov	109	26	26	26	27	27	27	27	28	26	26	26	26	318	27
Total Residential		35,267	35,472	35,648	35,678	35,464	35,500	35,306	35,547	35,260	35,431	35,393	35,305	425,271	35,439
Irrigation Time of Use	406	12	12	12	12	12	12	12	12	12	12	12	12	144	12
Irrigation Pumping	407	11	11	11	11	11	11	11	11	11	11	11	11	132	11
Total Irrigation		23	23	23	23	23	23	23	23	23	23	23	23	276	23
Sm Comm Demand - Net Metering	502	0	0	0	0	0	0	0	1	1	1	1	1	5	0
Small Commercial Demand	503	490	479	470	471	466	459	454	460	454	459	461	461	5,584	465
Small Commercial Energy	504	2,934	2,945	2,960	2,959	2,945	2,952	2,954	2,963	2,959	2,975	2,942	2,924	35,412	2,951
Small Commercial - Net Metering	505	0	0	1	5	5	5	5	5	5	5	6	7	49	4
Small Commercial TOU	506	4	7	8	8	8	8	8	8	8	8	8	8	91	8
SC Energy Gov	508	268	268	268	269	267	267	268	266	266	266	264	263	3,200	267
SC Demand Gov	509	65	66	66	66	66	66	66	66	65	65	66	62	785	65
Total Small Commercial		3,761	3,765	3,773	3,778	3,757	3,757	3,755	3,769	3,758	3,779	3,748	3,726	45,126	3,761
Large C&I Secondary	605	82	86	82	81	81	82	83	82	82	82	82	83	988	82
Large C&I Primary	605	3	3	3	3	3	3	3	3	3	3	3	3	36	3
Large C&I TOU	606	1	1	2	3	3	3	3	3	3	3	3	3	31	3
Large C&I GOV	609	30	30	30	31	29	29	29	30	31	31	31	31	362	30
LC&I Trans (Current TOU)	611	1	1	1	1	1	1	1	1	1	1	1	1	12	1
LC&I Substation (Current Contract)	612	1	1	1	1	1	1	1	1	1	1	1	1	12	1
LC&I Substation (Current LP)	615	1	1	1	1	1	1	1	1	1	1	1	1	12	1
Total Large Coml & Industrial		119	123	120	121	119	120	121	121	122	122	122	123	1,453	121
Lighting Devices		1,185	1,164	1,166	1,161	1,158	1,158	1,155	1,162	1,048	1,152	1,151	1,151	13,811	1,151
Resale		1	1	1	1	1	1	1	1	1	1	1	1	12	1
Total Excluding Lighting		39,171	39,384	39,565	39,601	39,364	39,401	39,206	39,461	39,164	39,356	39,287	39,178	472,138	39,345

MOHAVE ELECTRIC COOPERATIVE, INC.

CONSUMERS BY RATE SCHEDULE - ADJUSTED
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total	Average
Residential	101	34,765	34,761	35,397	35,097	34,733	34,714	34,621	34,733	34,672	34,596	34,563	34,650	417,302	34,775
Residential - Seasonal	102	2	2	2	1	1	1	1	1	0	0	0	0	11	1
Residential - Net Metering	105	0	3	47	72	77	82	88	91	98	100	101	104	863	72
Res - Gov	109	26	26	26	27	27	27	27	28	26	26	26	26	318	27
Total Residential		34,793	34,792	35,472	35,197	34,838	34,824	34,737	34,853	34,796	34,722	34,690	34,780	418,494	34,875
Irrigation Time of Use	406	12	12	12	12	12	12	12	12	12	12	12	12	144	12
Irrigation Pumping	407	11	11	11	11	11	11	11	11	11	11	11	11	132	11
Total Irrigation		23	23	23	23	23	23	23	23	23	23	23	23	276	23
Sm Comm Dmd - Net Metering	502	0	0	0	0	0	0	0	1	1	1	1	1	5	0
Small Commercial Demand	503	488	475	467	469	463	457	452	457	453	456	458	457	5,552	463
Small Commercial Energy	504	2,911	2,911	2,977	2,947	2,920	2,926	2,931	2,941	2,949	2,925	2,908	2,918	35,164	2,930
Small Commerical - Net Metering	505	0	0	1	5	5	5	5	5	5	5	6	7	49	4
Small Commercial TOU	506	4	7	8	8	8	8	8	8	8	8	8	8	91	8
SC Energy Gov	508	268	268	274	271	267	267	267	266	266	266	265	263	3,208	267
SC Demand Gov	509	65	66	66	66	66	66	66	66	66	64	65	62	784	65
Total Small Commercial		3,736	3,727	3,793	3,766	3,729	3,729	3,729	3,744	3,748	3,725	3,711	3,716	44,853	3,738
Large C&I Secondary	605	82	84	82	81	81	81	82	82	82	82	82	82	983	82
Large C&I Primary	605	3	3	3	3	3	3	3	3	3	3	3	3	36	3
Large C&I TOU	606	1	1	2	3	3	3	3	3	3	3	3	3	31	3
Large C&I GOV	609	30	30	30	31	29	29	29	30	31	31	31	31	362	30
LC&I Trans (Current TOU)	611	1	1	1	1	1	1	1	1	1	1	1	1	12	1
LC&I Substation (Current Contract	612	1	1	1	1	1	1	1	1	1	1	1	1	12	1
LC&I Substation (Current LP)	615	1	1	1	1	1	1	1	1	1	1	1	1	12	1
Total Large Coml & Industrial		119	121	120	121	119	119	120	121	122	122	122	122	1,448	121
Lighting Devices		1,182	1,164	1,166	1,161	1,158	1,158	1,155	1,162	1,048	1,152	1,151	1,151	13,808	1,151
Resale		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Excluding Lighting		38,671	38,663	39,408	39,107	38,709	38,695	38,609	38,741	38,689	38,592	38,546	38,641	465,071	38,756

Supplemental Schedule F-1.1

MOHAVE ELECTRIC COOPERATIVE, INC.

CONSUMERS BY RATE SCHEDULE - ADJUSTMENT
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total	Average
Residential	101	(474)	(680)	(176)	(481)	(626)	(676)	(569)	(694)	(464)	(709)	(703)	(525)	(6,777)	(565)
Residential - Seasonal	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential - Net Metering	105													0	0
Res - Gov	109	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Residential		(474)	(680)	(176)	(481)	(626)	(676)	(569)	(694)	(464)	(709)	(703)	(525)	(6,777)	(565)
Irrigation Time of Use	406	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Irrigation Pumping	407	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Irrigation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sm Comm Dmnd - Net Metering	502													0	0
Small Commercial Demand	503	(2)	(4)	(3)	(2)	(3)	(2)	(2)	(3)	(1)	(3)	(3)	(4)	(32)	(3)
Small Commercial Energy	504	(23)	(34)	17	(12)	(25)	(26)	(23)	(22)	(10)	(50)	(34)	(6)	(248)	(21)
Small Commerical - Net Metering	505													0	0
Small Commercial TOU	506	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SC Energy Gov	508	0	0	6	2	0	0	(1)	0	0	0	1	0	8	1
SC Demand Gov	509	0	0	0	0	0	0	0	0	1	(1)	(1)	0	(1)	0
Total Small Commercial		(25)	(38)	20	(12)	(28)	(28)	(26)	(25)	(10)	(54)	(37)	(10)	(273)	(23)
Large C&I Secondary	605	0	(2)	0	0	0	(1)	(1)	0	0	0	0	(1)	(5)	0
Large C&I Primary	605	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large C&I TOU	606	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large C&I GOV	609	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LC&I Trans (Current TOU)	611	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LC&I Substation (Current Contract)	612	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LC&I Substation (Current LP)	615	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Large Coml & Industrial		0	(2)	0	0	0	(1)	(1)	0	0	0	0	(1)	(5)	0
Lighting Devices		(3)	0	0	0	0	0	0	0	0	0	0	0	(3)	0
Resale		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Excluding Lighting		(499)	(720)	(156)	(493)	(654)	(705)	(596)	(719)	(474)	(763)	(740)	(536)	(7,055)	(588)

MOHAVE ELECTRIC COOPERATIVE, INC.

KWH SOLD BY RATE SCHEDULE - EXISTING
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Residential	101	25,849,475	21,682,468	19,197,187	18,556,599	20,450,231	29,930,248	47,944,080	56,760,772	51,765,675	30,864,964	19,880,637	21,229,417	364,111,753
Residential - Seasonal	102	0	0	1	0	0	0	0	548	0	0	0	0	549
Residential - Net Metering	105	0	398	13,288	16,374	23,004	33,953	77,774	159,445	141,903	79,565	44,468	49,888	640,060
Res - Gov	109	19,151	14,472	11,791	11,286	12,504	20,481	33,221	36,405	26,581	13,657	8,437	10,611	218,597
Total Residential		25,868,626	21,697,338	19,222,267	18,584,259	20,485,739	29,984,682	48,055,075	56,957,170	51,934,159	30,958,186	19,933,542	21,289,916	364,970,959
Irrigation Time of Use	406	13,824	32,327	56,968	148,711	210,413	242,921	264,488	304,783	229,249	140,818	800,158	(714,315)	1,730,345
Irrigation Pumping	407	79,943	79,256	140,125	234,689	281,040	379,623	366,338	330,171	288,032	167,864	105,312	119,614	2,572,007
Total Irrigation		93,767	111,583	197,093	383,400	491,453	622,544	630,826	634,954	517,281	308,682	905,470	(594,701)	4,302,352
Sm Comm Dmnd - Net Metering	502	0	0	0	0	0	0	0	4,440	6,280	5,080	4,000	4,480	24,280
Small Commercial Demand	503	4,670,602	4,096,614	4,037,334	4,406,968	4,661,116	5,430,165	6,812,189	7,420,720	7,340,476	5,411,838	5,286,189	3,445,267	63,019,478
Small Commercial Energy	504	2,928,167	2,646,724	2,482,268	2,463,406	2,628,627	3,117,971	4,178,953	4,732,727	4,689,267	3,335,715	2,659,842	2,677,764	38,541,431
Small Commerical - Net Metering	505	0	0	700	3,945	2,333	3,127	4,845	9,775	7,862	5,168	7,688	18,567	64,010
Small Commercial TOU	506	50,281	41,363	58,026	72,116	106,411	93,956	110,940	126,121	134,999	78,872	79,438	67,521	1,020,044
SC Energy Gov	508	343,302	291,556	268,042	263,634	258,209	272,253	322,869	354,676	368,940	277,819	258,290	279,560	3,559,150
SC Demand Gov	509	577,604	612,313	544,824	563,368	548,389	631,802	739,489	891,794	820,061	632,315	516,218	504,333	7,582,510
Total Small Commercial		8,569,956	7,688,570	7,391,194	7,773,437	8,205,085	9,549,274	12,169,285	13,540,253	13,367,885	9,746,807	8,811,665	6,997,492	113,810,903
Large C&I Secondary	605	5,944,240	5,356,960	5,089,824	5,296,320	5,704,834	6,221,160	7,781,600	8,424,240	8,319,520	6,595,680	5,841,800	5,734,880	76,311,058
Large C&I Primary	605	719,760	672,240	649,680	597,600	644,280	633,840	703,560	880,200	858,480	819,000	632,280	686,400	8,497,320
Large C&I TOU	606	5,280	4,280	11,640	60,360	69,080	63,600	65,440	78,280	62,080	29,040	62,320	53,480	564,880
Large C&I GOV	609	1,287,200	1,193,440	1,106,320	1,145,080	1,313,320	1,330,160	1,541,760	1,894,520	2,070,000	1,744,440	1,284,280	1,269,640	17,180,160
LC&I Trans (Current TOU)	611	2,244,000	1,512,000	1,722,000	2,178,000	2,880,000	2,820,000	3,486,000	2,268,000	3,282,000	3,414,000	2,520,000	1,878,000	30,204,000
LC&I Substation (Current Contract	612	2,611,200	2,409,600	3,110,400	2,798,400	2,913,600	2,980,800	2,932,800	2,961,600	2,913,600	3,739,200	3,264,000	3,033,600	35,668,800
LC&I Substation (Current LP)	615	397,200	290,400	254,400	246,000	194,400	210,000	274,800	282,000	270,000	172,800	214,800	326,400	3,133,200
Total Large Coml & Industrial		13,208,880	11,438,920	11,944,264	12,321,760	13,719,514	14,259,560	16,785,960	16,788,840	17,775,680	16,514,160	13,819,480	12,982,400	171,559,418
Lighting		94,004	92,858	93,045	92,085	92,392	92,455	92,248	92,455	82,475	92,085	91,959	92,042	1,100,103
Resale		12,722,216	15,762,000	8,993,000	1,514,000	1,124,000	403,000	326,000	1,267,000	339,500	157,000	50,516	4,204,729	46,862,961
Total		60,557,449	56,791,269	47,840,863	40,668,941	44,118,183	54,911,515	78,059,394	89,280,672	84,016,980	57,776,920	43,612,632	44,971,878	702,606,696

MOHAVE ELECTRIC COOPERATIVE, INC.

BASE REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Residential	101	2,480,685	2,133,993	1,933,283	1,877,148	2,031,215	2,819,680	4,317,364	5,051,890	4,635,770	2,896,320	1,982,215	2,095,250	34,254,813.07
Residential - Seasonal	102	19	19	18	10	10	10	10	55	0	0	0	0	148.64
Residential - Net Metering	105	0	69	1,807	2,380	3,066	4,033	7,780	14,632	12,827	8,121	5,225	5,742	65,681.35
Res - Gov	109	1,840	1,451	1,232	1,196	1,297	1,960	3,020	3,292	2,458	1,383	949	1,130	21,208.65
Total Residential		2,482,544	2,135,532	1,936,340	1,880,734	2,035,587	2,825,683	4,328,174	5,069,869	4,651,055	2,905,824	1,988,389	2,102,122	34,341,851.71
Irrigation Time of Use	406	2,588	4,125	5,405	12,453	15,295	17,055	17,173	16,809	15,194	11,852	42,597	(35,170)	125,374.98
Irrigation Pumping	407	10,164	11,036	16,460	22,385	24,355	31,169	30,556	28,358	25,234	16,828	12,276	12,567	241,387.92
Total Irrigation		12,752	15,162	21,865	34,838	39,650	48,224	47,728	45,167	40,428	28,680	54,872	(22,603)	366,762.90
Sm Comm Dmnd - Net Metering	502	0	0	0	0	0	0	0	431	532	439	240	393	2,034.67
Small Commercial Demand	503	373,001	340,868	338,103	362,836	386,155	440,516	528,972	568,985	559,454	445,725	421,003	310,446	5,076,064.28
Small Commercial Energy	504	273,875	250,905	238,281	236,382	249,535	289,540	376,175	421,482	418,030	307,294	251,944	253,523	3,566,967.51
Small Commerical - Net Metering	505	0	0	87	476	340	405	545	948	778	594	794	1,725	6,693.03
Small Commercial TOU	506	3,329	3,585	4,403	5,386	6,936	6,262	7,150	7,681	8,768	7,211	6,457	1,929	69,097.51
SC Energy Gov	508	31,229	27,008	25,158	24,759	24,274	25,420	29,552	32,134	33,297	25,862	24,254	25,973	328,919.52
SC Demand Gov	509	49,780	51,512	46,590	48,701	47,965	54,291	60,605	71,934	67,627	55,534	46,787	49,066	650,391.63
Total Small Commercial		731,215	673,879	652,622	678,539	715,206	816,434	1,002,999	1,103,594	1,088,487	842,658	751,479	643,055	9,700,168.15
Large C&I Secondary	605	460,225	427,123	413,466	420,793	450,101	490,406	584,360	625,144	615,348	532,022	471,471	465,111	5,955,570.79
Large C&I TOU	606	286	245	585	3,452	3,053	2,828	4,243	4,899	5,455	4,198	2,873	2,433	34,551.55
Large C&I GOV	609	104,466	98,882	93,062	99,306	111,554	111,881	119,552	143,860	168,352	148,005	119,789	117,377	1,436,086.94
LC&I Trans (Current TOU)	611	159,105	106,637	103,585	134,166	184,567	182,495	209,621	158,851	198,217	203,548	148,912	120,889	1,910,592.31
LC&I Substation (Current Contract)	612	106,158	129,939	162,248	125,355	135,660	146,395	147,738	140,937	130,321	161,454	135,294	128,564	1,650,061.16
LC&I Substation (Current LP)	615	25,662	20,677	18,638	17,250	13,494	14,556	18,094	19,008	17,759	13,094	15,945	21,967	216,143.94
Total Large Coml & Industrial		855,903	783,504	791,584	800,322	898,428	948,560	1,083,609	1,092,698	1,135,453	1,062,321	894,284	856,341	11,203,006.69
Lighting		8,326	8,245	8,252	8,180	8,200	8,205	8,180	8,197	7,449	8,167	8,161	8,163	97,724.87
Resale		523,940.00	647,256.00	370,345.00	75,799.00	58,659.00	20,342.00	16,456.00	48,118.00	17,705.00	7,878.00	2,527.00	39,785.00	1,826,810.00
PPCA Over/Under		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total		4,614,679.30	4,263,577.93	3,781,008.49	3,478,411.83	3,753,729.54	4,667,447.45	6,487,146.65	7,367,642.90	6,940,577.05	4,855,528.85	3,699,712.94	3,626,861.37	57,536,324.32

MOHAVE ELECTRIC COOPERATIVE, INC.

PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Residential	101	762,569.08	639,641.98	566,325.46	501,909.76	501,066.97	733,299.26	1,174,638.58	1,390,647.64	1,268,259.19	669,913.53	387,568.65	413,986.36	9,009,826.46
Residential - Seasonal	102	0.00	0.00	0.03	0.00	0.00	0.00	0.00	13.43	0.00	0.00	0.00	0.00	13.46
Residential - Net Metering	105	0.00	11.74	391.99	453.41	563.43	834.95	1,904.11	3,906.43	3,335.55	1,782.85	867.14	972.86	15,024.46
Res - Gov	109	564.95	426.93	347.82	299.37	306.35	501.79	813.92	891.94	651.24	268.24	164.50	206.92	5,443.97
Total Residential		763,134.03	640,080.65	567,065.30	502,662.54	501,936.75	734,636.00	1,177,356.61	1,395,459.44	1,272,245.98	671,964.62	388,600.29	415,166.14	9,030,308.35
Irrigation Time of Use	406	407.81	953.64	1,680.56	3,667.42	5,155.12	5,951.57	6,479.95	7,467.18	5,616.60	2,745.95	15,603.08	(13,985.29)	41,743.59
Irrigation Pumping	407	2,358.32	2,338.05	4,133.69	5,749.89	6,885.48	9,300.77	8,975.29	8,089.20	7,056.79	3,273.35	2,053.59	2,332.48	62,546.90
Total Irrigation		2,766.13	3,291.69	5,814.25	9,417.31	12,040.60	15,252.34	15,455.24	15,556.38	12,673.39	6,019.30	17,656.67	(11,652.81)	104,290.49
Sm Comm Dmnd - Net Metering	502	137,782.86	120,850.20	119,101.35	120,092.99	114,229.84	133,039.07	0.00	108.78	153.86	124.46	78.00	87.36	745,648.77
Small Commercial Demand	503	0.00	0.00	0.00	0.00	0.00	0.00	166,898.64	181,807.66	179,841.68	118,884.97	103,067.81	67,232.16	817,732.92
Small Commercial Energy	504	86,381.69	78,078.92	73,232.04	67,980.55	64,417.29	76,390.72	102,384.99	115,952.38	114,923.26	73,861.70	51,862.45	52,265.42	957,731.41
Small Commercial - Net Metering	505	0.00	0.00	20.65	101.85	57.16	76.61	118.71	239.49	192.62	113.58	149.92	362.06	1,432.65
Small Commercial TOU	506	1,483.29	1,220.21	1,711.77	2,108.20	2,607.08	2,301.93	2,718.03	3,089.96	3,307.48	1,538.00	1,549.05	1,170.41	24,805.41
SC Energy Gov	508	10,127.49	8,600.94	7,907.25	7,234.03	6,326.23	6,670.23	7,910.24	8,689.58	9,039.08	5,940.85	5,036.80	5,451.50	88,934.22
SC Demand Gov	509	17,039.31	18,063.23	16,072.32	15,068.38	13,435.55	15,479.15	18,117.49	21,848.95	20,091.49	13,740.97	10,066.25	9,834.49	188,857.58
Total Small Commercial		252,814.64	226,813.50	218,045.38	212,586.00	201,073.15	233,957.71	298,148.10	331,736.80	327,549.47	214,204.53	171,810.28	136,403.40	2,825,142.96
Large C&I Secondary	605	196,588.00	177,861.40	169,315.37	163,460.04	155,553.29	167,947.50	207,886.42	227,958.78	224,861.00	166,017.26	126,244.50	125,214.96	2,108,908.52
Large C&I TOU	606	155.76	126.26	343.38	1,701.22	1,692.46	1,558.20	1,603.28	1,917.86	1,520.96	566.28	1,215.24	1,042.86	13,443.76
Large C&I GOV	609	37,972.40	35,206.48	32,636.44	32,282.66	32,176.34	32,588.92	37,773.12	46,415.74	50,715.00	40,499.78	25,043.46	24,757.98	428,068.32
LC&I Trans (Current TOU)	611	66,198.00	44,604.00	50,799.00	53,361.00	70,560.00	69,090.00	85,407.00	55,566.00	80,409.00	66,573.00	49,140.00	36,621.00	728,328.00
LC&I Substation (Current Contract)	612	77,030.40	71,083.20	91,756.80	68,560.80	71,383.20	73,029.60	71,853.60	72,559.20	71,383.20	74,714.40	63,648.00	59,155.20	866,157.60
LC&I Substation (Current LP)	615	11,717.40	8,566.80	7,504.80	6,027.00	4,762.80	5,145.00	6,732.60	6,909.00	6,615.00	3,369.60	4,188.60	6,364.80	77,903.40
Total Large Coml & Industrial		389,661.96	337,448.14	352,355.79	325,392.72	336,128.09	349,359.22	411,256.02	411,326.58	435,504.16	351,740.32	269,479.80	253,156.80	4,222,809.60
Lighting		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Resale		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PPCA Over/Under		(865,878.00)	(542,014.00)	(161,760.00)	232,264.00	712,541.00	616,245.00	(397,445.00)	(1,684,580.00)	(2,155,586.00)	(272,919.00)	329,991.00	243,115.00	(3,946,026.00)
Total		542,498.76	665,619.98	981,520.72	1,282,322.57	1,763,719.59	1,949,450.27	1,504,770.97	469,499.20	(107,613.00)	971,009.77	1,177,538.04	1,036,188.53	12,236,525.40
Total Excluding Resale & Over/Under		1,408,376.76	1,207,633.98	1,143,280.72	1,050,058.57	1,051,178.59	1,333,205.27	1,902,215.97	2,154,079.20	2,047,973.00	1,243,928.77	847,547.04	793,073.53	16,182,551.40

MOHAVE ELECTRIC COOPERATIVE, INC.

TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Residential	101	3,243,253.81	2,773,635.40	2,499,608.84	2,379,058.06	2,532,281.83	3,552,979.67	5,492,002.48	6,442,537.38	5,904,029.00	3,566,233.60	2,369,783.46	2,509,236.00	43,264,639.53
Residential - Seasonal	102	19.00	19.00	17.55	9.53	9.50	9.50	9.50	68.52	0.00	0.00	0.00	0.00	162.10
Residential - Net Metering	105	0.00	80.36	2,199.00	2,833.31	3,628.97	4,867.78	9,684.59	18,538.09	16,162.43	9,903.80	6,092.45	6,715.03	80,705.81
Res - Gov	109	2,405.11	1,877.87	1,579.96	1,495.24	1,603.09	2,462.11	3,834.10	4,184.27	3,109.51	1,651.37	1,113.35	1,336.64	26,652.62
Total Residential		3,245,677.92	2,775,612.63	2,503,405.35	2,383,396.14	2,537,523.39	3,560,319.06	5,505,530.67	6,465,328.26	5,923,300.94	3,577,788.77	2,376,989.26	2,517,287.67	43,372,160.06
Irrigation Time of Use	406	2,995.67	5,079.01	7,085.89	16,120.43	20,449.97	23,006.14	23,652.75	24,276.43	20,810.37	14,597.89	58,199.72	(49,155.70)	167,118.57
Irrigation Pumping	407	12,522.04	13,374.24	20,593.53	28,135.19	31,240.18	40,470.13	39,530.84	36,447.17	32,290.65	20,101.68	14,329.42	14,899.75	303,934.82
Total Irrigation		15,517.71	18,453.25	27,679.42	44,255.62	51,690.15	63,476.27	63,183.59	60,723.60	53,101.02	34,699.57	72,529.14	(34,255.95)	471,053.39
Sm Comm Dmnd - Net Metering	502	137,782.86	120,850.20	119,101.35	120,092.99	114,229.84	133,039.07	0.00	539.33	686.30	563.37	317.96	480.17	747,683.44
Small Commercial Demand	503	373,001.18	340,868.36	338,103.00	362,835.54	386,155.03	440,516.40	695,870.81	750,793.07	739,295.85	564,609.65	524,070.50	377,677.81	5,893,797.20
Small Commercial Energy	504	360,257.16	328,984.19	311,513.28	304,362.64	313,952.78	365,930.79	478,559.59	537,434.51	532,953.40	381,155.56	303,806.33	305,788.69	4,524,698.92
Small Commerical - Net Metering	505	0.00	0.00	108.07	578.28	397.53	481.77	664.07	1,187.12	970.16	707.28	944.27	2,087.13	8,125.68
Small Commercial TOU	506	4,811.96	4,805.67	6,114.57	7,493.75	9,543.22	8,563.57	9,867.93	10,771.24	12,075.82	8,749.40	8,006.10	3,099.69	93,902.92
SC Energy Gov	508	41,356.87	35,608.75	33,065.03	31,992.74	30,600.10	32,090.13	37,462.29	40,823.14	42,336.57	31,802.50	29,291.27	31,424.35	417,853.74
SC Demand Gov	509	66,819.32	69,575.40	62,662.35	63,769.50	61,401.02	69,769.79	78,722.62	93,782.46	87,718.85	69,274.81	56,852.90	58,900.19	839,249.21
Total Small Commercial		984,029.35	900,692.57	870,667.65	891,125.44	916,279.52	1,050,391.52	1,301,147.31	1,435,330.87	1,416,036.95	1,056,862.57	923,289.33	779,458.03	12,525,311.11
Large C&I Secondary	605	656,813.35	604,984.70	582,781.14	584,253.23	605,654.01	658,353.50	792,246.89	853,102.67	840,209.16	698,039.07	597,715.80	590,325.79	8,064,479.31
Large C&I TOU	606	442.24	371.74	928.20	5,153.51	4,745.54	4,386.60	5,846.32	6,816.94	6,976.24	4,764.12	4,088.36	3,475.50	47,995.31
Large C&I GOV	609	142,438.58	134,088.68	125,698.49	131,588.77	143,730.06	144,469.50	157,325.07	190,275.70	219,067.25	188,505.14	144,832.83	142,135.19	1,864,155.26
LC&I Trans (Current TOU)	611	225,302.96	151,241.01	154,384.48	187,527.03	255,126.69	251,584.74	295,027.88	214,416.52	278,626.00	270,121.00	198,052.00	157,510.00	2,638,920.31
LC&I Substation (Current Contract)	612	183,187.90	201,021.78	254,004.86	193,915.37	207,043.52	219,424.11	219,591.83	213,495.83	201,704.48	236,168.46	198,941.70	187,718.92	2,516,218.76
LC&I Substation (Current LP)	615	37,379.78	29,244.23	26,143.05	23,276.68	18,256.55	19,700.80	24,826.98	25,916.56	24,373.60	16,463.82	20,133.18	28,332.11	294,047.34
Total Large Coml & Industrial		1,245,564.81	1,120,952.14	1,143,940.22	1,125,714.59	1,234,556.37	1,297,919.25	1,494,864.97	1,504,024.22	1,570,956.73	1,414,061.61	1,163,763.87	1,109,497.51	15,425,816.29
Lighting		8,326.27	8,245.32	8,251.57	8,179.61	8,199.70	8,204.62	8,180.08	8,197.15	7,449.41	8,167.10	8,161.38	8,162.64	97,724.87
Resale		523,940.00	647,256.00	370,345.00	75,799.00	56,659.00	20,342.00	16,456.00	48,118.00	17,705.00	7,878.00	2,527.00	39,785.00	1,826,810.00
PPCA Over/Under		(865,878.00)	(542,014.00)	(161,760.00)	232,264.00	712,541.00	616,245.00	(397,445.00)	(1,684,580.00)	(2,155,586.00)	(272,919.00)	329,991.00	243,115.00	(3,946,026.00)
Total		5,157,178.06	4,929,197.91	4,762,529.21	4,760,734.40	5,517,449.13	6,616,897.72	7,991,917.62	7,837,142.10	6,832,964.05	5,826,538.62	4,877,250.98	4,663,049.90	69,772,849.72
Total Excluding Resale & Over/Under		5,499,116.06	4,823,955.91	4,553,944.21	4,452,671.40	4,748,249.13	5,980,310.72	8,372,906.62	9,473,604.10	8,970,845.05	6,091,579.62	4,544,732.98	4,380,149.90	71,892,065.72

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 REVENUE UNDER EXISTING RATES

	Billing Units	Existing Rate	Existing Revenue
1. RESIDENTIAL SERVICE			
Residential			
Service Charge (12 Month Sum)	417,302	9.50	3,964,369
Energy Charge per kWh	364,111,753	0.083190	30,290,457
Base Revenue			34,254,826
PPCA Revenue			8,623,987
Total Revenue			42,878,813
Residential - Seasonal			
Service Charge (12 Month Sum)	11	9.50	105
Energy Charge per kWh	549	0.083190	46
Base Revenue			151
PPCA Revenue			13
Total Revenue			164
Residential - Net Metering			
Service Charge (12 Month Sum)	863	15.00	12,945
Energy Charge per kWh	640,060	0.083190	53,247
Base Revenue			66,192
PPCA Revenue			15,160
Total Revenue			81,352
Res - Gov			
Service Charge (12 Month Sum)	318	9.50	3,021
Energy Charge per kWh	218,597	0.083190	18,185
Base Revenue			21,206
PPCA Revenue			5,177
Total Revenue			26,383
Base Revenue	364,970,959		34,342,375
PPCA Revenue			8,644,337
Total Revenue			42,986,712

Customers from Supplemental Schedule F-1.1
Demand data from Supplemental Section R
kWh Usage from Supplemental Schedule F-2.0
PPCA Revenue from Supplemental Schedule F-5.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 REVENUE UNDER EXISTING RATES

	Billing Units	Existing Rate	Existing Revenue
2. IRRIGATION SERVICE			
Irrigation Time of Use			
Service Charge (12 Month Sum)	144	60.00	8,640
On-Peak Demand	2,234.49	13.50	30,166
NCP Demand	8,466.81	0.00	0
Energy Charge per kWh	1,730,345	0.050000	86,517
Base Revenue			125,323
PPCA Revenue			40,983
Total Revenue			166,306
Irrigation Pumping			
Service Charge (12 Month Sum)	132	60.00	7,920
NCP Demand	12,025.74	7.00	84,180
Energy Charge per kWh	2,572,007	0.058000	149,176
Base Revenue			241,276
PPCA Revenue			60,918
Total Revenue			302,194
Base Revenue	4,302,352		366,599
PPCA Revenue			101,901
Total Revenue			468,500
3. SMALL COMMERCIAL SERVICE			
Sm Comm Demand - Net Metering			
Service Charge (12 Month Sum)	5	25.00	125
NCP Demand > 3 kW	73.68	8.25	608
Energy Charge per kWh	24,280	0.053740	1,305
Base Revenue			2,038
PPCA Revenue			575
Total Revenue			2,613
Small Commercial Demand			
Service Charge (12 Month Sum)	5,552	25.00	138,800
NCP Demand > 3 kW	187,060.45	8.25	1,543,249
Energy Charge per kWh	63,019,478	0.053740	3,386,667
Base Revenue			5,068,716
PPCA Revenue			1,492,616
Total Revenue			6,561,332

Customers from Supplemental Schedule F-1.1
Demand data from Supplemental Section R
kWh Usage from Supplemental Schedule F-2.0
PPCA Revenue from Supplemental Schedule F-5.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 REVENUE UNDER EXISTING RATES

	Billing Units	Existing Rate	Existing Revenue
3. SMALL COMMERCIAL SERVICE *(Continued)*			
Small Commercial Energy			
Service Charge (12 Month Sum)	35,164	12.00	421,968
Energy Charge per kWh	38,541,431	0.081600	3,144,981
Base Revenue			3,566,949
PPCA Revenue			912,854
Total Revenue			4,479,803
Small Commercial - Net Metering			
Service Charge (12 Month Sum)	49	12.00	588
Energy Charge per kWh	64,010	0.081600	5,223
Base Revenue			5,811
PPCA Revenue			1,516
Total Revenue			7,327
Small Commercial TOU			
Service Charge (12 Month Sum)	91	30.00	2,730
On-Peak Demand	1,430.12	12.50	17,877
NCP kW	3,175.62	0.00	0
Energy Charge per kWh	1,020,044	0.050400	51,410
Base Revenue			72,017
PPCA Revenue			24,160
Total Revenue			96,177
SC Energy Gov			
Service Charge (12 Month Sum)	3,208	12.00	38,496
Energy Charge per kWh	3,559,150	0.081600	290,427
Base Revenue			328,923
PPCA Revenue			84,298
Total Revenue			413,221
SC Demand Gov			
Service Charge (12 Month Sum)	784	25.00	19,600
NCP Demand > 3 kW	26,495.68	8.25	218,589
Energy Charge per kWh	7,582,510	0.053740	407,484
Base Revenue			645,673
PPCA Revenue			179,592
Total Revenue			825,265
Base Revenue	113,810,903		9,690,127
PPCA Revenue			2,695,611
Total Revenue			12,385,738

Customers from Supplemental Schedule F-1.1
Demand data from Supplemental Section R
kWh Usage from Supplemental Schedule F-2.0
PPCA Revenue from Supplemental Schedule F-5.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 REVENUE UNDER EXISTING RATES

	Billing Units	Existing Rate	Existing Revenue
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE			
Large C&I Secondary			
Service Charge (12 Month Sum)	983	70.00	68,810
NCP Demand	189,369.16	9.75	1,846,349
Energy Charge per kWh	76,311,058	0.045580	3,478,258
Base Revenue			5,393,417
PPCA Revenue			1,807,427
Total Revenue			7,200,844
Large C&I Primary			
Service Charge (12 Month Sum)	36	70.00	2,520
NCP Demand	17,172.00	9.75	167,427
Energy Charge per kWh	8,497,320	0.045580	387,308
Base Revenue			557,255
PPCA Revenue			201,259
Total Revenue			758,514
Large C&I TOU			
Service Charge (12 Month Sum)	31	70.00	2,170
On-Peak Demand	690.80	13.50	9,326
NCP kW	5,713.20	0.00	0
Energy Charge per kWh	564,880	0.041000	23,160
Base Revenue			34,656
PPCA Revenue			13,379
Total Revenue			48,035
Large C&I GOV			
Service Charge (12 Month Sum)	362	70.00	25,340
NCP Demand	64,343.36	9.75	627,348
Energy Charge per kWh	17,180,160	0.045580	783,072
Base Revenue			1,435,760
PPCA Revenue			406,912
Total Revenue			1,842,672

Customers from Supplemental Schedule F-1.1
Demand data from Supplemental Section R
kWh Usage from Supplemental Schedule F-2.0
PPCA Revenue from Supplemental Schedule F-5.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 REVENUE UNDER EXISTING RATES

	Billing Units	Existing Rate	Existing Revenue
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)			
LC&I Trans (Current TOU)			
Service Charge (12 Month Sum)	12	70.00	840
On-Peak Demand	49,732.47	13.50	671,388
NCP kW	53,106.00	0.00	0
Energy Charge per kWh	30,204,000	0.041000	1,238,364
Base Revenue			1,910,592
PPCA Revenue			715,382
Total Revenue			2,625,974
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)			
LC&I Substation (Current Contract)	***Billed under LP Rate in future***		
Service Charge (12 Month Sum)	12	70.00	840
NCP kW	60,072.00	9.75	585,702
Energy Charge per kWh	35,668,800	0.045580	1,625,784
Base Revenue			2,212,326
PPCA Revenue			844,816
Total Revenue			3,057,142
LC&I Substation (Current LP)			
Service Charge (12 Month Sum)	12	70.00	840
NCP Demand	7,428.00	9.75	72,423
Energy Charge per kWh	3,133,200	0.045580	142,811
Base Revenue			216,074
PPCA Revenue			74,210
Total Revenue			290,284
Total LP Substation Base Revenue			2,428,400
PPCA Revenue			919,025
Total Revenue			3,347,425
Total LC & Industrial Base Revenue	171,559,418		11,760,080
PPCA Revenue			4,063,385
Total Revenue			15,823,465

Customers from Supplemental Schedule F-1.1
Demand data from Supplemental Section R
kWh Usage from Supplemental Schedule F-2.0
PPCA Revenue from Supplemental Schedule F-5.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 REVENUE UNDER EXISTING RATES

			Billing Units	Existing Rate	Existing Revenue
5.	**LIGHTING SERVICE**				
	175 W MVL	102 kWh per month	6,039	6.85	41,367
	100 W HPS	51 kWh per month	2,594	7.88	20,441
	175 W MVL CO	101 kWh per month	320	5.11	1,635
	100 W HPS CO	51 kWh per month	3,644	5.11	18,621
	250 W HPS	130 kWh per month	1,211	13.18	15,961
	Base Revenue		13,808		98,025
	PPCA Revenue				0
	Total Revenue				98,025
	kWh		1,100,103		
6.	**RESALE REVENUE**				
	Base Revenue				3,698,667
	PPCA Revenue				0
	Total Revenue		46,862,961		3,698,667
7.	**TOTAL REVENUE**				
	Base Revenue		702,606,696		59,955,873
	PPCA Revenue				15,505,234
	Other Revenue				606,899
	Total Revenue				76,068,007

Customers from Supplemental Schedule F-1.1
Demand data from Supplemental Section R
kWh Usage from Supplemental Schedule F-2.0
PPCA Revenue from Supplemental Schedule F-5.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 RESALE (TPS) REVENUE AND POWER COST
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Excess Baseload Energy														
Available Baseload Energy	(MWh)	92,249	83,367	48,064	91,757	94,700	96,850	100,048	100,175	96,679	92,250	89,306	92,297	1,077,742
Baseload Energy Used for Load	(MWh)	45,103	41,110	42,568	45,771	68,394	67,029	86,366	80,488	71,787	48,953	42,726	51,154	691,449
Total Excess Baseload Energy	(MWh)	47,146	42,257	5,495	45,986	26,306	29,821	13,682	19,687	24,892	43,297	46,580	41,143	386,292
Total Excess % of Total Available		51%	51%	11%	50%	28%	31%	14%	20%	26%	47%	52%	45%	36%
5x8 Excess Baseload Energy	(MWh)	12,687	11,564	1,020	11,140	1,533	3,551	5	476	1,433	9,439	11,547	11,919	76,314
5x8 Excess % of Total Available		27%	27%	19%	24%	6%	12%	0%	2%	6%	22%	25%	29%	20%
Potential Products														
Possible 5x8 Excess product @ 99.5% Threshold	(MW)	40.0	45.0	-	10.0	-	-	-	-	-	12.5	50.0	40.0	
Associated Energy	(MWh)	8,000	8,280	-	2,080	-	-	-	-	-	2,500	9,600	8,640	39,100
% of 5x8 Excess Utilized in Product		63%	72%	0%	19%	0%	0%	0%	0%	0%	26%	83%	72%	51%
% of Total Excess Utilized in Product		17%	20%	0%	5%	0%	0%	0%	0%	0%	6%	21%	21%	10%
Forwards			Q1			Q2			Q3			Q4		
Forwards [Enter SuperPk Adder, either 1 or 2]		36.11	35.30	35.20	35.50	35.35	37.05	48.40	46.65	40.65	39.45	38.30	41.45	
Adder for Delivery to Mead		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Adder for SuperPeak Product	0.20	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	
Total		46.93	46.12	46.02	46.32	46.17	47.87	59.22	57.47	51.47	50.27	49.12	52.27	
Margin for Third Party Sales														
Energy Sales kWh		12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	475,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Revenue $		595,440.21	533,363.01	46,925.51	516,048.85	70,784.07	169,979.55	267.76	27,347.71	73,778.47	474,505.21	567,197.09	623,029.25	3,698,666.69
Cost of Power $		535,827.74	488,394.61	43,062.54	470,499.99	64,746.00	149,958.54	190.95	20,096.52	60,536.13	398,630.87	487,656.54	503,379.38	3,222,979.80
Margin $		59,612.47	44,968.40	3,862.97	45,548.86	6,038.07	20,021.01	76.81	7,251.19	13,242.34	75,874.34	79,540.55	119,649.87	$\boxed{475,686.89}$
Margin $/kWh		0.004699	0.003889	0.003789	0.004089	0.003939	0.005639	0.016990	0.015239	0.009239	0.008039	0.006889	0.010039	0.006233

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh Sales													
Residential	25,849,475	21,682,468	19,197,187	18,556,599	20,450,231	29,930,248	47,944,080	56,760,772	51,765,675	30,864,964	19,880,637	21,229,417	364,111,753
Residential - Seasonal	0	0	1	0	0	0	0	548	0	0	0	0	549
Residential - Net Metering	0	398	13,288	16,374	23,004	33,953	77,774	159,445	141,903	79,565	44,468	49,888	640,060
Res - Gov	19,151	14,472	11,791	11,286	12,504	20,481	33,221	36,405	26,581	13,657	8,437	10,611	218,597
Irrigation Time of Use	13,824	32,327	56,968	148,711	210,413	242,921	264,488	304,783	229,249	140,818	800,158	-714,315	1,730,345
Irrigation Pumping	79,943	79,256	140,125	234,689	281,040	379,623	366,338	330,171	288,032	167,864	105,312	119,614	2,572,007
Sm Comm Dmd - Net Metering	0	0	0	0	0	0	0	4,440	6,280	5,080	4,000	4,480	24,280
Small Commercial Demand	4,670,602	4,096,614	4,037,334	4,406,968	4,661,116	5,430,165	6,812,189	7,420,720	7,340,476	5,411,838	5,286,189	3,445,267	63,019,476
Small Commercial Energy	2,928,167	2,646,724	2,482,268	2,463,406	2,628,627	3,117,971	4,178,953	4,732,727	4,689,267	3,335,715	2,659,842	2,677,764	38,541,431
Sm Comm Energy - Net Metering	0	0	700	3,945	2,333	3,127	4,845	9,775	7,862	5,168	7,688	18,567	64,010
Small Commercial TOU	50,281	41,363	58,026	72,116	106,411	93,956	110,940	126,121	134,999	78,872	79,436	67,521	1,020,044
SC Energy Gov	343,302	291,556	268,042	263,634	258,209	272,253	322,869	354,676	368,940	277,819	258,290	279,560	3,559,150
SC Demand Gov	577,604	612,313	544,824	563,368	548,389	631,802	739,489	891,794	820,061	632,315	516,218	504,333	7,582,510
Large C&I Secondary	5,944,240	5,356,960	5,089,824	5,296,320	5,704,834	6,221,160	7,781,600	8,424,240	8,319,520	6,595,680	5,841,800	5,734,880	76,311,058
Large C&I Primary	719,760	672,240	649,680	597,600	644,280	633,840	703,560	880,200	858,480	819,000	632,280	686,400	8,497,320
Large C&I TOU	5,280	4,280	11,640	60,360	69,080	63,600	65,440	78,280	62,080	29,040	62,320	53,480	564,880
Large C&I GOV	1,287,200	1,193,440	1,106,320	1,145,080	1,313,320	1,330,160	1,541,760	1,894,520	2,070,000	1,744,440	1,284,280	1,269,640	17,180,160
LC&I Trans (Current TOU)	2,244,000	1,512,000	1,722,000	2,178,000	2,880,000	2,820,000	3,486,000	2,268,000	3,282,000	3,414,000	2,520,000	1,878,000	30,204,000
LC&I Substation (Current Contract)	2,611,200	2,409,600	3,110,400	2,798,400	2,913,600	2,980,800	2,932,800	2,961,600	2,913,600	3,739,200	3,264,000	3,033,600	35,668,800
LC&I Substation (Current LP)	397,200	290,400	254,400	246,000	194,400	210,000	274,800	282,000	270,000	172,800	214,800	326,400	3,133,200
Lighting	94,004	92,858	93,045	92,085	92,392	92,455	92,248	92,455	82,475	92,085	91,959	92,042	1,100,103
Resale													0
Total excluding Resale	47,835,233	41,029,269	38,847,883	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Special Substation	-2,611,200	-2,409,600	-3,110,400	-2,798,400	-2,913,600	-2,980,800	-2,932,800	-2,961,600	-2,913,600	-3,739,200	-3,264,000	-3,033,600	-35,668,800
Less Lighting	-94,004	-92,858	-93,045	-92,085	-92,392	-92,455	-92,248	-92,455	-82,475	-92,085	-91,959	-92,042	-1,100,103
Jurisdictional kWh Sales	45,130,029	38,526,811	35,644,418	36,264,456	39,988,191	51,435,260	74,708,346	84,959,617	80,681,405	53,788,635	40,206,157	37,641,507	618,974,832
Calculated PPCA Revenue													
Actual Factor Applied	0.029500	0.029500	0.029500	0.026818	0.024500	0.024500	0.024500	0.024500	0.024500	0.021622	0.019500	0.019500	
Residential	762,559.51	639,632.81	566,317.02	497,650.87	501,030.66	733,291.08	1,174,629.96	1,390,638.91	1,268,259.04	667,362.25	387,672.42	413,973.63	9,003,018.16
Residential - Seasonal	0.00	0.00	0.03	0.00	0.00	0.00	0.00	13.43	0.00	0.00	0.00	0.00	13.46
Residential - Net Metering	0.00	11.74	392.00	439.12	563.60	831.85	1,905.46	3,906.40	3,476.62	1,720.35	867.13	972.82	15,087.09
Res - Gov	564.95	426.92	347.83	302.67	306.35	501.78	813.91	891.92	651.23	295.29	164.52	206.91	5,474.28
Irrigation Time of Use	407.81	953.65	1,680.56	3,988.13	5,155.12	5,951.56	6,479.96	7,467.18	5,616.60	3,044.77	15,603.08	(13,929.14)	42,419.28
Irrigation Pumping	2,358.32	2,338.05	4,133.69	6,293.89	6,885.48	9,300.76	8,975.28	8,089.19	7,056.78	3,629.56	2,053.58	2,332.47	63,447.05
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	108.78	153.86	109.84	78.00	87.36	537.84
Small Commercial Demand	137,782.76	120,850.11	119,101.35	118,186.07	114,197.34	133,039.04	166,898.63	181,807.64	179,841.66	117,014.76	103,080.69	67,182.71	1,558,982.76
Small Commercial Energy	86,380.93	78,078.36	73,226.91	66,063.62	64,401.36	76,390.29	102,384.35	115,951.81	114,887.04	72,124.83	51,866.92	52,216.40	953,972.82
Sm Comm Energy - Net Metering	0.00	0.00	20.65	105.80	57.16	76.61	118.70	239.49	192.62	111.74	149.92	362.06	1,434.75
Small Commercial TOU	1,483.29	1,220.21	1,711.77	1,934.01	2,607.07	2,301.92	2,718.03	3,089.96	3,307.48	1,705.37	1,549.04	1,316.66	24,944.81
SC Energy Gov	10,127.41	8,600.90	7,907.24	7,070.14	6,326.12	6,670.20	7,910.29	8,689.56	9,039.03	6,007.00	5,036.66	5,451.42	88,835.97
SC Demand Gov	17,039.32	18,063.23	16,072.31	15,108.40	13,435.53	15,479.15	18,117.48	21,848.95	20,091.49	13,671.91	10,066.25	9,834.49	188,828.51
Large C&I Secondary	175,355.08	158,030.32	150,149.81	142,036.71	139,788.43	152,418.42	190,649.20	206,393.88	203,828.24	142,611.79	113,915.10	111,830.16	1,886,987.14
Large C&I Primary	21,232.92	19,831.08	19,165.56	16,026.44	15,784.86	15,529.08	17,237.22	21,564.90	21,032.76	17,708.42	12,329.46	13,384.80	210,827.50
Large C&I TOU	155.76	126.26	343.38	1,618.73	1,692.46	1,558.20	1,603.28	1,917.86	1,520.96	627.90	1,215.24	1,042.86	13,422.89
Large C&I GOV	37,972.40	35,206.48	32,636.44	30,708.76	32,176.34	32,588.92	37,773.12	46,415.74	50,715.00	37,718.28	25,043.46	24,757.98	423,712.92
LC&I Trans (Current TOU)	66,198.00	44,604.00	50,799.00	58,409.60	70,560.00	69,090.00	85,407.00	55,566.00	80,409.00	73,817.51	49,140.00	36,621.00	740,621.11
LC&I Substation (Current Contract)	77,030.40	71,083.20	91,756.80	75,047.49	71,383.20	73,029.60	71,853.60	72,559.20	71,383.20	80,848.98	63,648.00	59,155.20	878,778.87
LC&I Substation (Current LP)	11,717.40	8,566.80	7,504.80	6,597.23	4,762.80	5,145.00	6,732.60	6,909.00	6,615.00	3,736.28	4,188.60	6,364.80	78,840.31
Total Large Coml & Industrial													0.00
Resale													0.00
Total	1,408,366.26	1,207,624.12	1,143,267.15	1,047,587.68	1,051,093.88	1,333,193.46	1,902,208.07	2,154,069.80	2,048,077.61	1,243,866.83	847,668.07	793,164.59	16,180,187.52
Test Year PPCA	1,408,376.76	1,207,633.98	1,143,280.72	1,050,058.57	1,051,178.59	1,333,205.27	1,902,215.97	2,154,079.20	2,047,973.00	1,243,928.77	847,547.04	793,073.53	16,182,551.40
Difference	(10.50)	(9.86)	(13.57)	(2,470.89)	(84.71)	(11.81)	(7.90)	(9.40)	104.61	(61.94)	121.03	91.06	(2,363.88)

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power frorm Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July
2010 Power Cost without Over/Under Fuel Bank							
Total kWh	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394
Less Special Substation	(2,611,200)	(2,409,600)	(3,110,400)	(2,798,400)	(2,913,600)	(2,980,800)	(2,932,800)
Less Lighting	(94,004)	(92,858)	(93,045)	(92,085)	(92,392)	(92,455)	(92,248)
Jurisdictional kWh Sales	45,130,029	38,526,811	35,644,418	36,264,456	39,988,191	51,435,260	74,708,346
Test Year Power Cost	4,132,182.17	3,969,075.72	3,846,008.41	3,849,335.95	4,575,027.86	5,468,104.86	6,572,468.67
Remove Special Substation	(167,864.36)	(186,947.20)	(235,214.32)	(177,488.36)	(189,954.20)	(201,958.89)	(202,415.03)
Remove AES Sales	(523,940.23)	(647,256.17)	(370,344.94)	(75,799.40)	(56,658.58)	(20,342.25)	(16,455.74)
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	3,440,377.58	3,134,872.35	3,240,449.15	3,596,048.19	4,328,415.08	5,265,803.72	6,353,597.90
Pur Pwr per Jurisd kWh Sold	0.076233	0.081369	0.090910	0.099162	0.108242	0.102377	0.085045
Power Cost in Base	2,969,465.65	2,534,987.11	2,345,331.42	2,386,128.68	2,631,142.99	3,384,337.24	4,915,659.75
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	470,911.93	599,885.24	895,117.73	1,209,919.51	1,697,272.09	1,881,466.48	1,437,938.15
Calculated PCA Factor	0.010435	0.015571	0.025112	0.033364	0.042444	0.036579	0.019247
Average PCA Factor	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419
Class Revenue							
Residential	476,121.48	399,369.38	353,592.99	341,794.00	376,672.80	551,285.24	883,082.01
Residential - Seasonal	0.00	0.00	0.02	0.00	0.00	0.00	0.00
Residential - Net Metering	0.00	7.33	244.75	301.59	423.71	625.38	1,432.52
Res - Gov	352.74	266.56	217.18	207.88	230.31	377.24	611.90
Irrigation Time of Use	254.62	595.43	1,049.29	2,739.11	3,875.60	4,474.36	4,871.60
Irrigation Pumping	1,472.47	1,459.82	2,580.96	4,322.74	5,176.48	6,992.28	6,747.58
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Commercial Demand	86,027.82	75,455.53	74,363.65	81,171.94	85,853.10	100,018.21	125,473.71
Small Commercial Energy	53,933.91	48,750.01	45,720.89	45,373.48	48,416.68	57,429.91	76,972.14
Sm Comm Energy - Net Metering	0.00	0.00	12.89	72.66	42.97	57.60	89.24
Small Commercial TOU	926.13	761.87	1,068.78	1,328.30	1,959.98	1,730.58	2,043.40
SC Energy Gov	6,323.28	5,370.17	4,937.07	4,855.87	4,755.95	5,014.63	5,946.92
SC Demand Gov	10,638.89	11,278.19	10,035.11	10,376.68	10,100.78	11,637.16	13,620.65
Large C&I Secondary	109,486.96	98,669.85	93,749.47	97,552.92	105,077.34	114,587.55	143,329.29
Large C&I Primary	13,257.26	12,381.99	11,966.46	11,007.19	11,866.99	11,674.70	12,958.87
Large C&I TOU	97.25	78.83	214.40	1,111.77	1,272.38	1,171.45	1,205.34
Large C&I GOV	23,708.94	21,981.97	20,377.31	21,091.23	24,190.04	24,500.22	28,397.68
LC&I Trans (Current TOU)	41,332.24	27,849.53	31,717.52	40,116.58	53,046.72	51,941.58	64,208.63
LC&I Substation (Current Contract)	48,095.69	44,382.42	57,290.46	51,543.73	53,665.60	54,903.36	54,019.24
LC&I Substation (Current LP)	7,316.03	5,348.88	4,685.79	4,531.07	3,580.65	3,867.99	5,061.54
Total Large Coml & Industrial							
Resale							
Total	879,345.71	754,007.76	713,824.99	719,498.74	790,208.08	1,002,289.44	1,430,072.26
Test Year PPCA	1,408,376.76	1,207,633.98	1,143,280.72	1,050,058.57	1,051,178.59	1,333,205.27	1,902,215.97
Calculated (Over)/Under	(529,031.05)	(453,626.22)	(429,455.73)	(330,559.83)	(260,970.51)	(330,915.83)	(472,143.71)
(Over)/Under Booked	(865,878.00)	(542,014.00)	(161,760.00)	232,264.00	712,541.00	616,245.00	(397,445.00)
Difference	336,846.95	88,387.78	(267,695.73)	(562,823.83)	(973,511.51)	(947,160.83)	(74,698.71)

	August	September	October	November	December	Total
2010 Power Cost without Over/Under Fuel Bank						
Total kWh	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Special Substation	(2,961,600)	(2,913,600)	(3,739,200)	(3,264,000)	(3,033,600)	(35,668,800)
Less Lighting	(92,455)	(82,475)	(92,085)	(91,959)	(92,042)	-1,100,103
Jurisdictional kWh Sales	84,959,617	80,681,405	53,788,635	40,206,157	37,641,507	618,974,832
Test Year Power Cost	6,232,141.19	5,327,519.03	4,666,127.99	3,879,020.08	3,757,050.58	56,294,062.51
Remove Special Substation	(191,867.72)	(212,522.98)	(192,609.67)	(182,385.58)	(164,155.39)	(2,305,383.70)
Remove AES Sales	(48,117.53)	(17,704.73)	(7,878.22)	(2,527.47)	(73,645.89)	(1,860,671.15)
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	5,992,155.94	5,097,291.32	4,465,640.10	3,694,107.03	3,519,249.30	52,128,007.66
Pur Pwr per Jurisd kWh Sold	0.070529	0.063178	0.083022	0.091879	0.093494	0.084217
Power Cost in Base	5,590,172.88	5,308,675.09	3,539,184.61	2,645,484.72	2,476,735.88	40,727,306.02
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	401,983.06	(211,383.77)	926,455.49	1,048,622.31	1,042,513.42	11,400,701.64
Calculated PCA Factor	0.004731	(0.002620)	0.017224	0.026081	0.027696	0.018419
Average PCA Factor	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419
Class Revenue						
Residential	1,045,476.66	953,471.97	568,501.77	366,181.45	391,024.63	6,706,574.38
Residential - Seasonal	10.09	0.00	0.00	0.00	0.00	10.11
Residential - Net Metering	2,936.82	2,613.71	1,465.51	819.06	918.89	11,789.27
Res - Gov	670.54	489.60	251.55	155.40	195.44	4,026.34
Irrigation Time of Use	5,613.80	4,222.54	2,593.73	14,738.11	(13,156.97)	31,871.22
Irrigation Pumping	6,081.42	5,305.26	3,091.89	1,939.74	2,203.17	47,373.81
Sm Comm Dmd - Net Metering	81.78	115.67	93.57	73.68	82.52	447.22
Small Commercial Demand	136,682.24	135,204.23	99,680.64	97,366.32	63,458.37	1,160,755.76
Small Commercial Energy	87,172.10	86,371.61	61,440.53	48,991.63	49,321.74	709,894.63
Sm Comm Energy - Net Metering	180.05	144.81	95.19	141.61	341.99	1,179.01
Small Commercial TOU	2,323.02	2,486.55	1,452.74	1,463.17	1,243.67	18,788.19
SC Energy Gov	6,532.78	6,795.51	5,117.15	4,757.44	5,149.22	65,555.99
SC Demand Gov	16,425.95	15,104.70	11,646.61	9,508.22	9,289.31	139,662.25
Large C&I Secondary	155,166.08	153,237.24	121,485.83	107,600.11	105,630.75	1,405,573.39
Large C&I Primary	16,212.40	15,812.34	15,085.16	11,645.97	12,642.80	156,512.13
Large C&I TOU	1,441.84	1,143.45	534.89	1,147.87	985.05	10,404.52
Large C&I GOV	34,895.16	38,127.33	32,130.84	23,655.15	23,385.50	316,441.37
LC&I Trans (Current TOU)	41,774.29	60,451.16	62,882.47	46,415.88	34,590.88	556,327.48
LC&I Substation (Current Contract)	54,549.71	53,665.60	68,872.32	60,119.62	55,875.88	656,983.63
LC&I Substation (Current LP)	5,194.16	4,973.13	3,182.80	3,956.40	6,011.96	57,710.40
Total Large Coml & Industrial						0.00
Resale						0.00
Total	1,619,420.89	1,539,736.41	1,059,605.19	800,676.83	749,194.80	12,057,881.10
Test Year PPCA	2,154,079.20	2,047,973.00	1,243,928.77	847,547.04	793,073.53	16,182,551.40
Calculated (Over)/Under	(534,658.31)	(508,236.59)	(184,323.58)	(46,870.21)	(43,878.73)	(4,124,670.30)
(Over)/Under Booked	(1,684,580.00)	(2,155,586.00)	(272,919.00)	329,991.00	243,115.00	(3,946,026.00)
Difference	1,149,921.69	1,647,349.41	88,595.42	(376,861.21)	(286,993.73)	(178,644.30)

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power from Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

2010 Power Cost With Special Substation transferred to standard rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
Total kWh	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Special Substation	0	0	0	0	0	0	0	0	0	0	0	0	1
Less Lighting	(94,004)	(92,858)	(93,045)	(92,085)	(92,392)	(92,455)	(92,248)	(92,455)	(82,475)	(92,085)	(91,959)	(92,042)	-1,100,103
Jurisdictional kWh Sales	47,741,229	40,936,411	38,754,818	39,062,856	42,901,791	54,416,060	77,641,146	87,921,217	83,595,005	57,527,835	43,470,157	40,675,107	654,643,633
Test Year Power Cost	4,132,182.17	3,969,075.72	3,846,008.41	3,849,335.95	4,575,027.86	5,488,104.86	6,572,468.67	6,232,141.19	5,327,519.03	4,666,127.99	3,879,020.08	3,757,050.58	56,294,062.51
Remove Special Substation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove AES Sales	(523,940.23)	(647,256.17)	(370,344.94)	(75,799.40)	(56,658.58)	(20,342.25)	(16,455.74)	(48,117.53)	(17,704.73)	(7,878.22)	(2,527.47)	(73,645.89)	(1,860,671.15)
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	3,608,241.94	3,321,819.55	3,475,663.47	3,773,536.55	4,518,369.28	5,467,762.61	6,556,012.93	6,184,023.66	5,309,814.30	4,658,249.77	3,876,492.61	3,683,404.69	54,433,391.36
Pur Pwr per Jurisd kWh Sold	0.075579	0.081146	0.089683	0.096602	0.105319	0.100481	0.084440	0.070336	0.063518	0.080974	0.089176	0.090557	0.083150
Power Cost in Base	3,141,277.39	2,693,533.98	2,549,989.52	2,570,257.80	2,822,852.05	3,580,467.92	5,108,632.13	5,785,040.24	5,500,384.14	3,785,216.49	2,860,249.39	2,676,340.69	43,074,241.74
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	466,964.55	628,285.57	925,673.95	1,203,278.75	1,695,517.23	1,887,294.69	1,447,380.80	398,983.42	(190,569.84)	873,033.28	1,016,243.22	1,007,064.00	11,359,149.62
Calculated PPCA Factor	0.009781	0.015348	0.023885	0.030804	0.039521	0.034683	0.018642	0.004538	(0.002280)	0.015176	0.023378	0.024759	0.017352
Average PPCA Factor	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352
Class Revenue													
Residential	448,540.09	376,234.18	333,109.59	321,994.11	354,852.41	519,349.66	831,925.68	984,912.92	898,237.99	535,568.86	344,968.81	368,372.84	6,318,067.14
Residential - Seasonal	0.00	0.00	0.02	0.00	0.00	0.00	0.00	9.51	0.00	0.00	0.00	0.00	9.53
Residential - Net Metering	0.00	6.91	230.57	284.12	399.17	589.15	1,349.53	2,766.69	2,462.30	1,380.61	771.61	865.66	11,106.32
Res - Gov	332.31	251.12	204.60	195.83	216.97	355.39	576.45	631.70	461.23	236.98	146.40	184.12	3,793.10
Irrigation Time of Use	239.87	560.94	988.51	2,580.43	3,651.09	4,215.17	4,589.40	5,288.59	3,977.93	2,443.47	13,884.34	(12,394.79)	30,024.95
Irrigation Pumping	1,387.17	1,375.25	2,431.45	4,072.32	4,876.61	6,587.22	6,356.70	5,729.13	4,997.93	2,912.78	1,827.37	2,075.54	44,629.47
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.04	108.97	88.15	69.41	77.74	421.31
Small Commercial Demand	81,044.29	71,084.45	70,055.82	76,469.71	80,879.68	94,224.22	118,205.10	128,764.33	127,371.94	93,906.21	91,725.95	59,782.27	1,093,513.97
Small Commercial Energy	50,809.55	45,925.95	43,072.31	42,745.02	45,611.94	54,103.03	72,513.19	82,122.28	81,368.16	57,881.33	46,153.58	46,464.56	668,770.90
Sm Comm Energy - Net Metering													
Small Commercial TOU	872.48	717.73	1,006.87	1,251.36	1,846.44	1,630.32	1,925.03	2,188.45	2,342.50	1,368.59	1,378.41	1,171.62	17,699.80
SC Energy Gov	5,956.98	5,059.08	4,651.06	4,574.58	4,480.44	4,724.13	5,602.42	6,154.34	6,401.85	4,820.72	4,481.85	4,850.93	61,758.38
SC Demand Gov	10,022.58	10,624.86	9,453.79	9,775.56	9,515.65	10,963.03	12,831.61	15,474.41	14,229.70	10,971.93	8,957.41	8,751.19	131,571.72
Large C&I Secondary	103,144.45	92,953.97	88,318.63	91,901.74	98,990.28	107,949.57	135,026.32	146,177.41	144,360.31	114,448.24	101,366.91	99,511.64	1,324,149.47
Large C&I Primary	12,489.28	11,664.71	11,273.25	10,369.56	11,179.55	10,998.39	12,208.17	15,273.23	14,896.34	14,211.29	10,971.32	11,910.41	147,445.50
Large C&I TOU	91.62	74.27	201.98	1,047.37	1,198.68	1,103.59	1,135.51	1,358.31	1,077.21	503.90	1,081.38	927.98	9,801.80
Large C&I GOV	22,335.49	20,708.57	19,196.86	19,869.43	22,788.73	23,080.94	26,752.62	32,873.71	35,918.64	30,269.52	22,284.83	22,030.79	298,110.13
LC&I Trans (Current TOU)	38,937.89	26,236.22	29,880.14	37,792.68	49,973.76	46,932.64	60,489.07	39,354.34	56,949.26	59,239.73	43,727.04	32,587.06	524,099.81
LC&I Substation (Current Contract)	45,309.54	41,811.38	53,971.66	48,557.84	50,556.79	51,722.84	50,889.95	51,389.68	50,556.79	64,882.60	56,636.93	52,639.03	618,925.03
LC&I Substation (Current LP)	6,892.21	5,039.02	4,414.35	4,268.59	3,373.23	3,643.92	4,768.33	4,893.26	4,685.04	2,998.43	3,727.21	5,663.69	54,367.28
Total Large Coml & Industrial													0.00
Resale													0.00
Total	828,405.80	710,328.61	672,461.46	677,750.23	744,391.42	944,173.21	1,347,145.08	1,525,439.33	1,450,404.09	998,133.34	754,160.76	705,472.28	11,358,265.61
Test Year without Fuel Bank	879,345.71	754,007.76	713,824.99	719,498.74	790,208.08	1,002,289.44	1,430,072.26	1,619,420.89	1,539,736.41	1,059,605.19	800,676.83	749,194.80	12,057,881.10
Difference	(50,939.91)	(43,679.15)	(41,363.53)	(41,748.51)	(45,816.66)	(58,116.23)	(82,927.18)	(93,981.56)	(89,332.32)	(61,471.85)	(46,516.07)	(43,722.52)	(699,615.49)

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power frorm Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Adjusted 2010 Power Cost													
Total kWh	47,835,233	41,029,269	38,847,663	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Lighting	(94,004)	(92,858)	(93,045)	(92,085)	(92,392)	(92,455)	(92,248)	(92,455)	(82,475)	(92,085)	(91,959)	(92,042)	(1,100,103)
Jurisdictional kWh Sales	47,741,229	40,936,411	38,754,818	39,062,856	42,901,791	54,416,060	77,641,146	87,921,217	83,595,005	57,527,835	43,470,157	40,675,107	654,643,632
Adjusted PP	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Remove Special Substation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove AES Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Pur Pwr per Jurisd kWh Sold	0.085497	0.094218	0.102327	0.109603	0.110467	0.103115	0.086975	0.070634	0.065663	0.081947	0.102393	0.108820	0.089483
Power Cost in Base	3,141,277.39	2,693,533.97	2,549,989.51	2,570,257.80	2,822,852.04	3,580,467.92	5,108,632.12	5,785,040.24	5,500,384.14	3,785,216.49	2,860,249.39	2,676,340.69	43,074,241.70
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	940,456.39	1,163,402.42	1,415,657.75	1,711,159.39	1,916,371.60	2,030,655.74	1,644,174.06	425,160.64	(11,292.09)	928,993.88	1,590,806.86	1,749,908.36	15,505,455.00
Calculated PPCA Factor	0.019699	0.028420	0.036529	0.043805	0.044669	0.037317	0.021177	0.004836	(0.000135)	0.016149	0.036595	0.043022	0.023685
Average PPCA Factor	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685
Class Revenue													
Residential	612,244.82	513,549.25	454,685.37	439,513.05	484,363.72	708,897.92	1,135,555.53	1,344,378.88	1,226,070.01	731,036.67	470,872.89	502,818.74	8,623,986.85
Residential - Seasonal	0.00	0.00	0.02	0.00	0.00	0.00	0.00	12.98	0.00	0.00	0.00	0.00	13.00
Residential - Net Metering	0.00	9.43	314.73	387.82	544.85	804.18	1,842.08	3,776.45	3,360.97	1,884.50	1,053.22	1,181.60	15,159.83
Res - Gov	453.59	342.77	279.27	267.31	296.16	485.09	786.84	862.25	629.57	323.47	199.83	251.32	5,177.47
Irrigation Time of Use	327.42	765.66	1,349.29	3,522.22	4,983.63	5,753.58	6,264.40	7,218.79	5,429.76	3,335.27	18,951.74	(16,918.55)	40,983.21
Irrigation Pumping	1,893.45	1,877.18	3,318.86	5,558.61	6,656.43	8,991.37	8,676.72	7,820.10	6,822.04	3,975.86	2,494.31	2,833.06	60,917.99
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	105.16	148.74	120.32	94.74	106.11	575.07
Small Commercial Demand	110,623.21	97,028.30	95,624.26	104,379.04	110,398.53	128,613.46	161,346.70	175,759.75	173,859.17	128,179.38	125,203.39	81,601.15	1,492,616.34
Small Commercial Energy	69,353.64	62,687.66	58,792.52	58,345.77	62,259.03	73,849.14	98,978.50	112,094.64	111,065.29	79,006.41	62,998.36	63,422.84	912,853.80
Sm Comm Energy - Net Metering	0.00	0.00	16.58	93.44	55.26	74.06	114.75	231.52	186.21	122.40	182.09	439.76	1,516.07
Small Commercial TOU	1,190.91	979.68	1,374.35	1,708.07	2,520.34	2,225.35	2,627.61	2,987.18	3,197.45	1,868.08	1,881.49	1,599.23	24,159.74
SC Energy Gov	8,131.11	6,905.50	6,348.57	6,244.17	6,115.68	6,448.31	7,647.15	8,400.50	8,738.34	6,580.14	6,117.60	6,621.38	84,298.45
SC Demand Gov	13,680.55	14,502.63	12,904.16	13,343.37	12,988.59	14,964.23	17,514.80	21,122.14	19,423.14	14,976.38	12,226.62	11,945.13	179,591.74
Large Power	140,789.32	126,879.60	120,552.48	125,443.34	135,118.99	147,348.17	184,307.20	199,528.12	197,047.83	156,218.68	138,363.03	135,830.63	1,807,427.39
Large Power Primary	17,047.52	15,922.00	15,387.67	14,154.16	15,259.77	15,012.50	16,663.82	20,847.54	20,333.10	19,398.02	14,975.55	16,257.38	201,259.03
LP TOU	125.06	101.37	275.69	1,429.63	1,636.16	1,506.37	1,549.95	1,854.06	1,470.36	687.81	1,476.05	1,266.67	13,379.18
LP Gov	30,467.33	28,266.63	26,203.19	27,121.22	31,105.98	31,504.84	36,516.59	44,871.71	49,027.95	41,317.06	30,418.17	30,071.42	406,912.09
LP Trans (Current TOU)	53,149.14	35,811.72	40,785.57	51,585.93	68,212.80	66,791.70	82,565.91	53,717.58	77,734.17	80,860.59	59,686.20	44,480.43	715,381.74
LP Substation (Current Contract)	61,846.27	57,071.38	73,669.82	66,280.10	69,008.62	70,600.25	69,463.37	70,145.50	69,008.62	88,562.95	77,307.84	71,850.82	844,815.54
LP Substation (Current LP)	9,407.68	6,878.12	6,025.46	5,826.51	4,604.36	4,973.85	6,508.64	6,679.17	6,394.95	4,092.77	5,087.54	7,730.78	74,209.83
Lighting													0.00
Resale													0.00
Total	1,130,751.02	969,578.88	917,907.86	925,203.76	1,016,128.90	1,288,844.37	1,838,930.56	2,082,414.02	1,979,947.67	1,362,546.76	1,029,590.66	963,389.90	15,505,234.36
Adjusted PPCA	828,405.80	710,328.61	672,461.46	677,750.23	744,391.42	944,173.21	1,347,145.08	1,525,439.33	1,450,404.09	998,133.34	754,160.76	705,472.28	11,358,265.61
Difference	302,345.22	259,250.27	245,446.40	247,453.53	271,737.48	344,671.16	491,785.48	556,974.69	529,543.58	364,413.42	275,429.90	257,917.62	4,146,968.75

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power from Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh Sales													
Residential	25,849,475	21,682,468	19,197,187	18,556,599	20,450,231	29,930,248	47,944,080	56,760,772	51,765,675	30,864,964	19,880,637	21,229,417	364,111,753
Residential - Seasonal	0	0	1	0	0	0	0	548	0	0	0	0	549
Residential - Net Metering	0	398	13,288	16,374	23,004	33,953	77,774	159,445	141,903	79,565	44,468	49,888	640,060
Res - Gov	19,151	14,472	11,791	11,286	12,504	20,481	33,221	36,405	26,581	13,657	8,437	10,611	218,597
Irrigation Time of Use	13,824	32,327	56,968	148,711	210,413	242,921	264,488	304,783	229,249	140,818	800,158	-714,315	1,730,345
Irrigation Pumping	79,943	79,256	140,125	234,689	281,040	379,623	366,338	330,171	288,032	167,864	105,312	119,614	2,572,007
Sm Comm Dmd - Net Metering	0	0	0	0	0	0	0	4,440	6,280	5,080	4,000	4,480	24,280
Small Commercial Demand	4,670,602	4,096,614	4,037,334	4,406,968	4,661,116	5,430,165	6,612,189	7,420,720	7,340,476	5,411,838	5,286,189	3,445,267	63,019,478
Small Commercial Energy	2,928,167	2,646,724	2,482,268	2,463,406	2,628,627	3,117,971	4,178,953	4,732,727	4,689,267	3,335,715	2,659,842	2,677,764	38,541,431
Sm Comm Energy - Net Metering	0	0	700	3,945	2,333	3,127	4,845	9,775	7,862	5,168	7,688	18,567	64,010
Small Commercial TOU	50,281	41,363	58,026	72,116	106,411	93,956	110,940	126,121	134,999	78,872	79,438	67,521	1,020,044
SC Energy Gov	343,302	291,556	268,042	263,634	258,209	272,253	322,869	354,676	368,940	277,819	258,290	279,560	3,559,150
SC Demand Gov	577,604	612,313	544,824	563,368	548,389	631,802	739,489	891,794	820,061	632,315	516,218	504,333	7,582,510
Large C&I Secondary	5,944,240	5,356,960	5,089,824	5,296,320	5,704,834	6,221,160	7,781,600	8,424,240	8,319,520	6,595,680	5,841,800	5,734,880	76,311,058
Large C&I Primary	719,760	672,240	649,680	597,600	644,280	633,840	703,560	880,200	858,480	819,000	632,280	686,400	8,497,320
Large C&I TOU	5,280	4,280	11,640	60,360	69,080	63,600	65,440	78,280	62,080	29,040	62,320	53,480	564,880
Large C&I GOV	1,287,200	1,193,440	1,106,320	1,145,080	1,313,320	1,330,160	1,541,760	1,894,520	2,070,000	1,744,440	1,284,280	1,269,640	17,180,160
LC&I Trans (Current TOU)	2,244,000	1,512,000	1,722,000	2,178,000	2,880,000	2,820,000	3,486,000	2,268,000	3,282,000	3,414,000	2,520,000	1,878,000	30,204,000
LC&I Substation (Current Contract)	2,611,200	2,409,600	3,110,400	2,798,400	2,913,600	2,980,800	2,932,800	2,961,600	2,913,600	3,739,200	3,264,000	3,033,600	35,668,800
LC&I Substation (Current LP)	397,200	290,400	254,400	246,000	194,400	210,000	274,800	282,000	270,000	172,800	214,800	326,400	3,133,200
Lighting	94,004	92,858	93,045	92,085	92,392	92,455	92,248	92,455	82,475	92,085	91,959	92,042	1,100,103
Resale													0
Total excluding Resale	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Special Substation	-2,611,200	-2,409,600	-3,110,400	-2,798,400	-2,913,600	-2,980,800	-2,932,800	-2,961,600	-2,913,600	-3,739,200	-3,264,000	-3,033,600	-35,668,800
Less Lighting	-94,004	-92,858	-93,045	-92,085	-92,392	-92,455	-92,248	-92,455	-82,475	-92,085	-91,959	-92,042	-1,100,103
Jurisdictional kWh Sales	45,130,029	38,526,811	35,644,418	36,264,456	39,988,191	51,435,260	74,708,346	84,959,617	80,681,405	53,788,635	40,206,157	37,641,507	618,974,832
Calculated PPCA Revenue													
Actual Factor Applied	0.029500	0.029500	0.029500	0.026818	0.024500	0.024500	0.024500	0.024500	0.024500	0.021622	0.019500	0.019500	
Residential	762,559.51	639,632.81	566,317.02	497,650.87	501,030.66	733,291.08	1,174,629.96	1,390,638.91	1,268,259.04	667,362.25	387,672.42	413,973.63	9,003,018.16
Residential - Seasonal	0.00	0.00	0.03	0.00	0.00	0.00	0.00	13.43	0.00	0.00	0.00	0.00	13.46
Residential - Net Metering	0.00	11.74	392.00	439.12	563.60	831.85	1,905.46	3,906.40	3,476.62	1,720.35	867.13	972.82	15,087.09
Res - Gov	564.95	426.92	347.83	302.67	306.35	501.78	813.91	891.92	651.23	295.29	164.52	206.91	5,474.28
Irrigation Time of Use	407.81	953.65	1,680.56	3,988.13	5,155.12	5,951.56	6,479.96	7,467.18	5,616.60	3,044.77	15,603.08	(13,929.14)	42,419.28
Irrigation Pumping	2,358.32	2,338.05	4,133.69	6,293.89	6,885.48	9,300.76	8,975.28	8,089.19	7,056.78	3,629.56	2,053.58	2,332.47	63,447.05
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	108.78	153.86	109.84	78.00	87.36	537.84
Small Commercial Demand	137,782.76	120,850.11	119,101.35	118,186.07	114,197.34	133,039.04	166,898.63	181,807.64	179,841.66	117,014.76	103,080.69	67,182.71	1,558,982.76
Small Commercial Energy	86,380.93	78,078.36	73,226.91	66,063.62	64,401.36	76,390.29	102,384.35	115,951.81	114,887.04	72,124.83	51,866.92	52,216.40	953,972.82
Sm Comm Energy - Net Metering	0.00	0.00	20.65	105.80	57.16	76.61	118.70	239.49	192.62	111.74	149.92	362.06	1,434.75
Small Commercial TOU	1,483.29	1,220.21	1,711.77	1,934.01	2,607.07	2,301.92	2,718.03	3,089.96	3,307.48	1,705.37	1,549.04	1,316.66	24,944.81
SC Energy Gov	10,127.41	8,600.90	7,907.24	7,070.14	6,326.12	6,670.20	7,910.29	8,689.56	9,039.03	6,007.00	5,036.66	5,451.42	88,835.97
SC Demand Gov	17,039.32	18,063.23	16,072.31	15,108.40	13,435.53	15,479.15	18,117.48	21,848.95	20,091.49	13,671.91	10,066.25	9,834.49	188,828.51
Large C&I Secondary	175,355.08	158,030.32	150,149.81	142,036.71	139,768.43	152,418.42	190,649.20	206,393.88	203,828.24	142,611.79	113,915.10	111,830.16	1,886,987.14
Large C&I Primary	21,232.92	19,831.08	19,165.56	16,026.44	15,784.86	15,529.08	17,237.22	21,564.90	21,032.76	17,708.42	12,329.46	13,384.80	210,827.50
Large C&I TOU	155.76	126.26	343.38	1,618.73	1,692.46	1,558.20	1,603.28	1,917.86	1,520.96	627.90	1,215.24	1,042.86	13,422.89
Large C&I GOV	37,972.40	35,206.48	32,636.44	30,708.76	32,176.34	32,588.92	37,773.12	46,415.74	50,715.00	37,718.28	25,043.46	24,757.98	423,712.92
LC&I Trans (Current TOU)	66,198.00	44,604.00	50,799.00	58,409.60	70,560.00	69,090.00	85,407.00	55,566.00	80,409.00	73,817.51	49,140.00	36,621.00	740,621.11
LC&I Substation (Current Contract)	77,030.40	71,083.20	91,756.80	75,047.49	71,383.20	73,029.60	71,853.60	72,559.20	71,383.20	80,848.98	63,648.00	59,155.20	878,778.87
LC&I Substation (Current LP)	11,717.40	8,566.80	7,504.80	6,597.23	4,762.80	5,145.00	6,732.60	6,909.00	6,615.00	3,736.28	4,188.60	6,364.80	78,840.31
Total Large Coml & Industrial													0.00
Resale													0.00
Total	1,408,366.26	1,207,824.12	1,143,267.15	1,047,587.68	1,051,093.88	1,333,193.46	1,902,208.07	2,154,069.80	2,048,077.61	1,243,866.83	847,668.07	793,164.59	16,180,187.52
Test Year PPCA	1,408,376.76	1,207,833.98	1,143,280.72	1,050,058.57	1,051,178.59	1,333,205.27	1,902,215.97	2,154,079.20	2,047,973.00	1,243,928.77	847,547.04	793,073.53	16,182,551.40
Difference	(10.50)	(9.86)	(13.57)	(2,470.89)	(84.71)	(11.81)	(7.90)	(9.40)	104.61	(61.94)	121.03	91.06	(2,363.88)

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power from Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2010 Power Cost without Over/Under Fuel Bank													
Total kWh	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Special Substation	(2,611,200)	(2,409,600)	(3,110,400)	(2,798,400)	(2,913,600)	(2,980,800)	(2,932,800)	(2,961,600)	(2,913,600)	(3,739,200)	(3,264,000)	(3,033,600)	(35,668,800)
Less Lighting	(94,004)	(92,858)	(93,045)	(92,085)	(92,392)	(92,455)	(92,248)	(92,455)	(82,475)	(92,085)	(91,959)	(92,042)	-1,100,103
Jurisdictional kWh Sales	45,130,029	38,526,811	35,644,418	36,264,456	39,988,191	51,435,260	74,708,346	84,959,617	80,681,405	53,788,635	40,206,157	37,641,507	618,974,832
Test Year Power Cost	4,132,182.17	3,969,075.72	3,846,008.41	3,849,335.95	4,575,027.86	5,488,104.86	6,572,468.67	6,232,141.19	5,327,519.03	4,666,127.99	3,879,020.08	3,757,050.58	56,294,062.51
Remove Special Substation	(167,864.36)	(186,947.20)	(235,214.32)	(177,488.36)	(189,954.20)	(201,958.89)	(202,415.03)	(191,867.72)	(212,522.98)	(192,609.67)	(182,385.58)	(164,155.39)	(2,305,383.70)
Remove AES Sales	(523,940.23)	(647,256.17)	(370,344.94)	(75,799.40)	(56,658.58)	(20,342.25)	(16,455.74)	(48,117.53)	(17,704.73)	(7,878.22)	(2,527.47)	(73,645.89)	(1,860,671.15)
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	3,440,377.58	3,134,872.35	3,240,449.15	3,596,048.19	4,328,415.08	5,265,803.72	6,353,597.90	5,992,155.94	5,097,291.32	4,465,640.10	3,694,107.03	3,519,249.30	52,128,007.66
Pur Pwr per Jurisd kWh Sold	0.076233	0.081369	0.090910	0.099162	0.108242	0.102377	0.085045	0.070529	0.063178	0.083022	0.091879	0.093494	0.084217
Power Cost in Base	2,969,465.65	2,534,987.11	2,345,331.42	2,386,128.68	2,631,142.99	3,384,337.24	4,915,659.75	5,590,172.88	5,308,675.09	3,539,184.61	2,645,484.72	2,476,735.88	40,727,306.02
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	470,911.93	599,885.24	895,117.73	1,209,919.51	1,697,272.09	1,881,466.48	1,437,938.15	401,983.06	(211,383.77)	926,455.49	1,048,622.31	1,042,513.42	11,400,701.64
Calculated PCA Factor	0.010435	0.015571	0.025112	0.033364	0.042444	0.036579	0.019247	0.004731	(0.002620)	0.017224	0.026081	0.027696	0.018419
Average PCA Factor	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419	0.018419
Class Revenue													
Residential	476,121.48	399,369.38	353,592.99	341,794.00	376,672.80	551,285.24	883,082.01	1,045,476.66	953,471.97	568,501.77	366,181.45	391,024.63	6,706,574.38
Residential - Seasonal	0.00	0.00	0.02	0.00	0.00	0.00	0.00	10.09	0.00	0.00	0.00	0.00	10.11
Residential - Net Metering	0.00	7.33	244.75	301.59	423.71	625.38	1,432.52	2,936.82	2,613.71	1,465.51	819.06	918.89	11,789.27
Res - Gov	352.74	266.56	217.18	207.88	230.31	377.24	611.90	670.54	489.60	251.55	155.40	195.44	4,026.34
Irrigation Time of Use	254.62	595.43	1,049.29	2,739.11	3,875.60	4,474.36	4,871.60	5,613.80	4,222.54	2,593.73	14,738.11	(13,156.97)	31,871.22
Irrigation Pumping	1,472.47	1,459.82	2,580.96	4,322.74	5,176.48	6,992.28	6,747.58	6,081.42	5,305.26	3,091.89	1,939.74	2,203.17	47,373.81
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	81.78	115.67	93.57	73.68	82.52	447.22
Small Commercial Demand	86,027.82	75,455.53	74,363.65	81,171.94	85,853.10	100,018.21	125,473.71	136,682.24	135,204.23	99,680.64	97,366.32	63,458.37	1,160,755.76
Small Commercial Energy	53,933.91	48,750.01	45,720.89	45,373.48	48,416.68	57,429.91	76,972.14	87,172.10	86,371.61	61,440.53	48,991.63	49,321.74	709,894.63
Sm Comm Energy - Net Metering	0.00	0.00	12.89	72.66	42.97	57.60	89.24	180.05	144.81	95.19	141.61	341.99	1,179.01
Small Commercial TOU	926.13	761.87	1,068.78	1,328.30	1,959.98	1,730.58	2,043.40	2,323.02	2,486.55	1,452.74	1,463.17	1,243.67	18,788.19
SC Energy Gov	6,323.28	5,370.17	4,937.07	4,855.87	4,755.95	5,014.83	5,946.92	6,532.78	6,795.51	5,117.15	4,757.44	5,149.22	65,555.99
SC Demand Gov	10,638.89	11,278.19	10,035.11	10,376.68	10,100.78	11,637.16	13,620.65	16,425.95	15,104.70	11,646.61	9,508.22	9,289.31	139,662.25
Large C&I Secondary	109,486.96	98,669.86	93,749.47	97,552.92	105,077.34	114,587.55	143,329.29	155,166.08	153,237.24	121,485.83	107,600.11	105,630.75	1,405,573.39
Large C&I Primary	13,257.26	12,381.99	11,966.46	11,007.19	11,866.99	11,674.70	12,958.87	16,212.40	15,812.34	15,085.16	11,645.97	12,642.80	156,512.13
Large C&I TOU	97.25	78.83	214.40	1,111.77	1,272.38	1,171.45	1,205.34	1,441.84	1,143.45	534.89	1,147.87	985.05	10,404.62
Large C&I GOV	23,708.94	21,981.97	20,377.31	21,091.23	24,190.04	24,500.22	28,397.68	34,895.16	38,127.33	32,130.84	23,655.15	23,385.50	316,441.37
LC&I Trans (Current TOU)	41,332.24	27,849.53	31,717.52	40,116.56	53,046.72	51,941.58	64,208.63	41,774.29	60,451.16	62,882.47	46,415.88	34,590.88	556,327.48
LC&I Substation (Current Contract)	48,095.69	44,382.42	57,290.46	51,543.73	53,665.60	54,903.36	54,019.24	54,549.71	53,665.60	68,872.32	60,119.62	55,875.88	656,983.63
LC&I Substation (Current LP)	7,316.03	5,348.88	4,685.79	4,531.07	3,580.65	3,867.99	5,061.54	5,194.16	4,973.13	3,182.80	3,956.40	6,011.96	57,710.40
Total Large Coml & Industrial													0.00
Resale													0.00
Total	879,345.71	754,007.76	713,824.99	719,498.74	790,208.08	1,002,289.44	1,430,072.26	1,619,420.89	1,539,736.41	1,059,605.19	800,676.83	749,194.80	12,057,881.10
Test Year PPCA	1,408,376.76	1,207,633.98	1,143,280.72	1,050,058.57	1,051,178.59	1,333,205.27	1,902,215.97	2,154,079.20	2,047,973.00	1,243,928.77	847,547.04	793,073.53	16,182,551.40
Calculated (Over)/Under	(529,031.05)	(453,626.22)	(429,455.73)	(330,559.83)	(260,970.51)	(330,915.83)	(472,143.71)	(534,658.31)	(508,236.59)	(184,323.58)	(46,870.21)	(43,878.73)	(4,124,670.30)
(Over)/Under Booked	(865,878.00)	(542,014.00)	(161,760.00)	232,264.00	712,541.00	616,245.00	(397,445.00)	(1,684,580.00)	(2,155,586.00)	(272,919.00)	329,991.00	243,115.00	(3,946,026.00)
Difference	336,846.95	88,387.78	(267,695.73)	(562,823.83)	(973,511.51)	(947,160.83)	(74,698.71)	1,149,921.69	1,647,349.41	88,595.42	(376,861.21)	(286,993.73)	(178,644.30)

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power frorm Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2010 Power Cost With Special Substation transferred to standard rate													
Total kWh	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Special Substation	0	0	0	0	0	0	0	0	0	0	0	0	1
Less Lighting	(94,004)	(92,858)	(93,045)	(92,085)	(92,392)	(92,455)	(92,248)	(92,455)	(82,475)	(92,085)	(91,959)	(92,042)	-1,100,103
Jurisdictional kWh Sales	47,741,229	40,936,411	38,754,818	39,062,856	42,901,791	54,416,060	77,641,146	87,921,217	83,595,005	57,527,835	43,470,157	40,675,107	654,643,633
Test Year Power Cost	4,132,182.17	3,969,075.72	3,846,008.41	3,849,335.95	4,575,027.86	5,488,104.86	6,572,468.67	6,232,141.19	5,327,519.03	4,666,127.99	3,879,020.08	3,757,050.58	56,294,062.51
Remove Special Substation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove AES Sales	(523,940.23)	(647,256.17)	(370,344.94)	(75,799.40)	(56,658.58)	(20,342.25)	(16,455.74)	(48,117.53)	(17,704.73)	(7,878.22)	(2,527.47)	(73,645.89)	(1,860,671.15)
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	3,608,241.94	3,321,819.55	3,475,663.47	3,773,536.55	4,518,369.28	5,467,762.61	6,556,012.93	6,184,023.66	5,309,814.30	4,658,249.77	3,876,492.61	3,683,404.69	54,433,391.36
Pur Pwr per Jurisd kWh Sold	0.075579	0.081146	0.089683	0.096602	0.105319	0.100481	0.084440	0.070336	0.063518	0.080974	0.089176	0.090557	0.083150
Power Cost in Base	3,141,277.39	2,693,533.98	2,549,989.52	2,570,257.80	2,822,852.05	3,580,467.92	5,108,632.13	5,785,040.24	5,500,384.14	3,785,216.49	2,860,249.39	2,676,340.69	43,074,241.74
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	466,964.55	628,285.57	925,673.95	1,203,278.75	1,695,517.23	1,887,294.69	1,447,380.80	398,983.42	(190,569.84)	873,033.28	1,016,243.22	1,007,064.00	11,359,149.62
Calculated PPCA Factor	0.009781	0.015348	0.023885	0.030804	0.039521	0.034683	0.018642	0.004538	(0.002280)	0.015176	0.023378	0.024759	0.017352
Average PPCA Factor	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352	0.017352
Class Revenue													
Residential	448,540.09	376,234.18	333,109.59	321,994.11	354,852.41	519,349.66	831,925.68	984,912.92	898,237.99	535,568.86	344,968.81	368,372.84	6,318,067.14
Residential - Seasonal	0.00	0.00	0.02	0.00	0.00	0.00	0.00	9.51	0.00	0.00	0.00	0.00	9.53
Residential - Net Metering	0.00	6.91	230.57	284.12	399.17	589.15	1,349.53	2,766.69	2,462.30	1,380.61	771.61	865.66	11,106.32
Res - Gov	332.31	251.12	204.60	195.83	216.97	355.39	576.45	631.70	461.23	236.98	146.40	184.12	3,793.10
Irrigation Time of Use	239.87	560.94	988.51	2,580.43	3,651.09	4,215.17	4,589.40	5,288.59	3,977.93	2,443.47	13,884.34	(12,394.79)	30,024.95
Irrigation Pumping	1,387.17	1,375.25	2,431.45	4,072.32	4,876.61	6,587.22	6,356.70	5,729.13	4,997.93	2,912.78	1,827.37	2,075.54	44,629.47
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.04	108.97	88.15	69.41	77.74	421.31
Small Commercial Demand	81,044.29	71,084.45	70,055.82	76,469.71	80,879.68	94,224.22	118,205.10	128,764.33	127,371.94	93,906.21	91,725.95	59,782.27	1,093,513.97
Small Commercial Energy	50,809.55	45,925.95	43,072.31	42,745.02	45,611.94	54,103.03	72,513.19	82,122.28	81,368.16	57,881.33	46,153.58	46,464.56	668,770.90
Sm Comm Energy - Net Metering													
Small Commercial TOU	872.48	717.73	1,006.87	1,251.36	1,846.44	1,630.32	1,925.03	2,188.45	2,342.50	1,368.59	1,378.41	1,171.62	17,699.80
SC Energy Gov	5,956.98	5,059.08	4,651.06	4,574.58	4,480.44	4,724.13	5,602.42	6,154.34	6,401.85	4,820.72	4,481.85	4,850.93	61,758.38
SC Demand Gov	10,022.58	10,624.86	9,453.79	9,775.56	9,515.65	10,963.03	12,831.61	15,474.41	14,229.70	10,971.93	8,957.41	8,751.19	131,571.72
Large C&I Secondary	103,144.45	92,953.97	88,318.63	91,901.74	98,990.28	107,949.57	135,026.32	146,177.41	144,360.31	114,448.24	101,366.91	99,511.64	1,324,149.47
Large C&I Primary	12,489.28	11,664.71	11,273.25	10,369.56	11,179.55	10,998.39	12,208.17	15,273.23	14,896.34	14,211.29	10,971.32	11,910.41	147,445.50
Large C&I TOU	91.82	74.27	201.98	1,047.37	1,198.68	1,103.59	1,135.51	1,358.31	1,077.21	503.90	1,081.38	927.98	9,801.80
Large C&I GOV	22,335.49	20,708.57	19,196.86	19,869.43	22,788.73	23,080.94	26,752.62	32,873.71	35,918.64	30,269.52	22,284.83	22,030.79	298,110.13
LC&I Trans (Current TOU)	38,937.89	26,236.22	29,880.14	37,792.66	49,973.76	48,932.64	60,489.07	39,354.34	56,949.26	59,239.73	43,727.04	32,587.06	524,099.81
LC&I Substation (Current Contract)	45,309.54	41,811.38	53,971.66	48,557.84	50,556.79	51,722.84	50,889.95	51,389.68	50,556.79	64,882.60	56,636.93	52,639.03	618,925.03
LC&I Substation (Current LP)	6,892.21	5,039.02	4,414.35	4,268.59	3,373.23	3,643.92	4,768.33	4,893.26	4,685.04	2,998.43	3,727.21	5,663.69	54,367.28
Total Large Coml & Industrial													0.00
Resale													0.00
Total	828,405.80	710,328.61	672,461.46	677,750.23	744,391.42	944,173.21	1,347,145.08	1,525,439.33	1,450,404.09	998,133.34	754,160.76	705,472.28	11,358,265.61
Test Year without Fuel Bank	879,345.71	754,007.76	713,824.99	719,498.74	790,208.08	1,002,289.44	1,430,072.26	1,619,420.89	1,539,736.41	1,059,605.19	800,676.83	749,194.80	12,057,881.10
Difference	(50,939.91)	(43,679.15)	(41,363.53)	(41,748.51)	(45,816.66)	(58,116.23)	(82,927.18)	(93,981.56)	(89,332.32)	(61,471.85)	(46,516.07)	(43,722.52)	(699,615.49)

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power from Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 PURCHASED POWER COST ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

Adjusted 2010 Power Cost	January	February	March	April	May	June	July	August	September	October	November	December	Total
Total kWh	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Lighting	(94,004)	(92,858)	(93,045)	(92,085)	(92,392)	(92,455)	(92,248)	(92,455)	(82,475)	(92,085)	(91,959)	(92,042)	(1,100,103)
Jurisdictional kWh Sales	47,741,229	40,936,411	38,754,818	39,062,856	42,901,791	54,416,060	77,641,146	87,921,217	83,595,005	57,527,835	43,470,157	40,675,107	654,643,632
Adjusted PP	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Remove Special Substation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove AES Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Pur Pwr per Jurisd kWh Sold	0.085497	0.094218	0.102327	0.109603	0.110467	0.103115	0.086975	0.070634	0.065663	0.081947	0.102393	0.108820	0.089483
Power Cost in Base	3,141,277.39	2,693,533.97	2,549,989.51	2,570,257.80	2,822,852.04	3,580,467.92	5,108,632.12	5,785,040.24	5,500,384.14	3,785,216.49	2,860,249.39	2,676,340.69	43,074,241.70
Authorized Base Cost	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798	0.065798
Power Cost to Collect	940,456.39	1,163,402.42	1,415,657.75	1,711,159.39	1,916,371.60	2,030,655.74	1,644,174.06	425,160.64	(11,292.09)	928,993.88	1,590,806.86	1,749,908.36	15,505,455.00
Calculated PPCA Factor	0.019699	0.028420	0.036529	0.043805	0.044669	0.037317	0.021177	0.004836	(0.000135)	0.016149	0.036595	0.043022	0.023685
Average PPCA Factor	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685	0.023685
Class Revenue													
Residential	612,244.82	513,549.25	454,685.37	439,513.05	484,363.72	708,897.92	1,135,555.53	1,344,378.88	1,226,070.01	731,036.67	470,872.89	502,818.74	8,623,986.85
Residential - Seasonal	0.00	0.00	0.02	0.00	0.00	0.00	0.00	12.98	0.00	0.00	0.00	0.00	13.00
Residential - Net Metering	0.00	9.43	314.73	387.82	544.85	804.18	1,842.08	3,776.45	3,360.97	1,884.50	1,053.22	1,181.60	15,159.83
Res - Gov	453.59	342.77	279.27	267.31	296.16	485.09	786.84	862.25	629.57	323.47	199.83	251.32	5,177.47
Irrigation Time of Use	327.42	765.66	1,349.29	3,522.22	4,983.63	5,753.58	6,264.40	7,218.79	5,429.76	3,335.27	18,951.74	(16,918.55)	40,983.21
Irrigation Pumping	1,893.45	1,877.18	3,318.86	5,558.61	6,656.43	8,991.37	8,676.72	7,820.10	6,822.04	3,975.86	2,494.31	2,833.06	60,917.99
Sm Comm Dmd - Net Metering	0.00	0.00	0.00	0.00	0.00	0.00	0.00	105.16	148.74	120.32	94.74	106.11	575.07
Small Commercial Demand	110,623.21	97,028.30	95,624.26	104,379.04	110,398.53	128,613.46	161,346.70	175,759.75	173,859.17	128,179.38	125,203.39	81,601.15	1,492,616.34
Small Commercial Energy	*69,353.64*	*62,687.66*	*58,792.52*	*58,345.77*	*62,259.03*	*73,649.14*	*98,978.50*	*112,094.64*	*111,065.29*	*79,006.41*	62,998.36	63,422.84	912,853.80
Sm Comm Energy - Net Metering	0.00	0.00	16.58	93.44	55.26	74.06	114.75	231.52	186.21	122.40	182.09	439.76	1,516.07
Small Commercial TOU	1,190.91	979.68	1,374.35	1,708.07	2,520.34	2,225.35	2,627.61	2,987.18	3,197.45	1,868.08	1,881.49	1,599.23	24,159.74
SC Energy Gov	8,131.11	6,905.50	6,348.57	6,244.17	6,115.68	6,448.31	7,647.15	8,400.50	8,738.34	6,580.14	6,117.60	6,621.38	84,298.45
SC Demand Gov	13,680.55	14,502.63	12,904.16	13,343.37	12,988.59	14,964.23	17,514.80	21,122.14	19,423.14	14,976.38	12,226.62	11,945.13	179,591.74
Large Power	140,789.32	126,879.60	120,552.48	125,443.34	135,118.99	147,348.17	184,307.20	199,528.12	197,047.83	156,218.68	138,363.03	135,830.63	1,807,427.39
Large Power Primary	17,047.52	15,922.00	15,387.67	14,154.16	15,259.77	15,012.50	16,663.82	20,847.54	20,333.10	19,398.02	14,975.55	16,257.38	201,259.03
LP TOU	125.06	101.37	275.69	1,429.63	1,636.16	1,506.37	1,549.95	1,854.06	1,470.36	687.81	1,476.05	1,266.67	13,379.18
LP Gov	30,487.33	28,266.63	26,203.19	27,121.22	31,105.98	31,504.84	36,516.59	44,871.71	49,027.95	41,317.06	30,418.17	30,071.42	406,912.09
LP Trans (Current TOU)	53,149.14	35,811.72	40,785.57	51,585.93	68,212.80	66,791.70	82,565.91	53,717.58	77,734.17	80,860.59	59,686.20	44,480.43	715,381.74
LP Substation (Current Contract)	61,846.27	57,071.38	73,669.82	66,280.10	69,008.62	70,600.25	69,463.37	70,145.50	69,008.62	88,562.95	77,307.84	71,850.82	844,815.54
LP Substation (Current LP)	*9,407.68*	*6,878.12*	*6,025.46*	*5,826.51*	*4,604.36*	*4,973.85*	*8,508.64*	*6,679.17*	*6,394.95*	*4,092.77*	5,087.54	7,730.78	*74,209.83*
Lighting													0.00
Resale													0.00
Total	1,130,751.02	969,578.88	917,907.86	925,203.76	1,016,128.90	1,288,844.37	1,838,930.56	2,082,414.02	1,979,947.67	1,362,546.76	1,029,590.66	963,389.90	15,505,234.36
Adjusted PPCA	828,405.80	710,328.61	672,461.46	677,750.23	744,391.42	944,173.21	1,347,145.08	1,525,439.33	1,450,404.09	998,133.34	754,160.76	705,472.28	11,358,265.61
Difference	302,345.22	259,250.27	245,446.40	247,453.53	271,737.48	344,671.16	491,785.48	556,974.69	529,543.58	364,413.42	275,429.90	257,917.62	4,146,968.75

kWh Sales from Sup Schedule F-2.0
Existing Purchased Power from Sup Schedule F-6.0 - Adjusted Purchased Power Cost from Sup Schedule F-7.0
Existing PPCA Revenue from Sup Schedule F-3.1

MOHAVE ELECTRIC COOPERATIVE, INC.

2010 PURCHASED POWER
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Date and Time of Peak x Resale	5 07:30	8 07:30	11 07:30	26 17:30	31 17:00	28 16:30	15 16:30	25 16:30	4 16:30	1 15:30	3 16:30	31 18:30	
MEC Integrated Hourly Load @ Mohave peak	81,107	76,077	73,446	90,887	119,436	171,444	200,713	186,810	173,322	134,609	89,602	88,622	1,486,075
Date and Time of Peak x Resale	25 8:00	22 20:00	12 7:00	26 18:00	31 17:00	29 17:00	19 16:00	15 16:00	5 15:00	1 16:00	29 20:00	31 19:00	0
MEC Integrated Hourly Load @ SWT peak	79,207	74,856	69,944	90,758	119,321	169,751	191,061	172,779	164,403	134,068	80,278	88,011	1,434,437
Total Billing kWh Purchased	59,920,764	54,811,942	51,776,942	43,422,860	53,277,983	68,771,159	93,239,055	86,650,731	68,150,633	51,840,890	43,763,427	49,523,085	725,149,471
Resale at Purchased Level	(12,722,216)	(15,762,000)	(8,993,000)	(1,514,000)	(1,124,000)	(403,000)	(326,000)	(1,267,000)	(339,500)	(157,000)	(50,516)	(4,204,729)	(46,862,961)
Losses, Imbalance Etc.	(355,650)	(336,906)	(1,091,777)	(378,996)	(661,556)	2,709,763	2,452,051	197,703	1,372,897	(257,903)	78,427	136,644	3,864,697
Total Metered kWh Purch for Mohave	46,842,898	38,713,036	41,692,165	41,529,864	51,492,427	71,077,922	95,365,106	85,581,434	69,184,030	51,425,987	43,791,338	45,455,000	682,151,207
Total Billing													
Total Generation	3,519,315.88	3,342,178.37	3,208,108.89	3,292,300.36	3,951,702.46	4,884,914.08	5,998,638.88	5,611,195.90	4,718,149.75	4,055,341.54	3,271,455.36	3,181,284.94	3,181,284.94
Total Transmission	604,947.79	607,470.33	574,458.47	541,028.76	550,753.67	556,050.50	561,805.41	554,541.80	559,415.62	564,692.34	541,575.57	550,221.07	550,221.07
Total	4,124,263.67	3,949,648.70	3,782,567.36	3,833,329.12	4,502,456.13	5,440,964.58	6,560,444.29	6,165,737.70	5,277,565.37	4,620,033.88	3,813,030.93	3,731,506.01	55,801,547.74
Own Use	(4,570.27)	(4,051.44)	(4,587.87)	(5,515.71)	(6,034.08)	(8,952.11)	(10,941.10)	(9,789.89)	(7,924.53)	(6,450.42)	(5,396.68)	(4,993.80)	(79,207.90)
Total Power Cost Acct 555	4,119,693.40	3,945,597.26	3,777,979.49	3,827,813.41	4,496,422.05	5,432,012.47	6,549,503.19	6,155,947.81	5,269,640.84	4,613,583.46	3,807,634.25	3,726,512.21	55,722,339.84
Other Exp Pwr Supply Acct 557	12,488.77	23,478.46	68,028.92	21,522.54	78,605.81	56,092.39	22,965.48	76,193.38	57,878.19	52,544.53	71,385.83	30,538.37	571,722.67
Total Power Cost	4,132,182.17	3,969,075.72	3,846,008.41	3,849,335.95	4,575,027.86	5,488,104.86	6,572,468.67	6,232,141.19	5,327,519.03	4,666,127.99	3,879,020.08	3,757,050.58	56,294,062.51
Non-Member Power Sales													
Power Cost for Resale	523,940.23	647,256.17	370,344.94	75,799.40	56,658.58	20,342.25	16,455.74	48,117.53	17,704.73	7,878.22	2,527.47	73,645.89	1,860,671.15
Sales to Other													-
Total	523,940.23	647,256.17	370,344.94	75,799.40	56,658.58	20,342.25	16,455.74	48,117.53	17,704.73	7,878.22	2,527.47	73,645.89	1,860,671.15
Mohave Power Cost													
Mohave System Remainder Pur Pwr	3,608,241.94	3,321,819.55	3,475,663.47	3,773,536.55	4,518,369.28	5,467,762.61	6,556,012.93	6,184,023.66	5,309,814.30	4,658,249.77	3,876,492.61	3,683,404.69	54,433,391.36

MOHAVE ELECTRIC COOPERATIVE, INC.

ADJUSTED 2010 PURCHASED POWER EXCLUDING RESALE (THIRD PARTY SALES)
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Date and Time of Peak x Resale	5 07:30	8 07:30	11 07:30	26 17:30	31 17:00	28 16:30	15 16:30	25 16:30	4 16:30	1 15:30	3 16:30	31 18:30	
MEC Integrated Hourly Load @ Mohave peak	81,107	76,077	73,446	90,887	119,436	171,444	200,713	186,810	173,322	134,609	89,602	88,622	1,486,075
Date and Time of Peak x Resale	25 8:00	22 20:00	12 7:00	26 18:00	31 17:00	29 17:00	19 16:00	15 16:00	5 15:00	1 16:00	29 20:00	31 19:00	
Projected Network 1	79,207	74,856	69,944	90,758	119,321	169,751	191,061	172,779	164,403	134,068	80,278	88,011	1,434,437
Projected Network 2	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC Integrated Hourly Load @ SWT peak	79,207	74,856	69,944	90,758	119,321	169,751	191,061	172,779	164,403	134,068	80,278	88,011	1,434,437
WAPA 06 DSR-11498	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	60,000
WAPA 06 DSR-11500	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	180,000
WAPA 06 DSR-11501	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	180,000
Total WAPA Direct kW	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	420,000
Estimated kWh Break-down													
Total Metered kWh Purch for Mohave	46,842,898	38,713,036	41,692,165	41,529,864	51,492,427	71,077,922	95,365,106	85,581,434	69,184,030	51,425,987	43,791,338	45,455,000	682,151,207
Adj Losses, Imbalance Etc.	(355,650)	(336,906)	(1,091,777)	(378,996)	(661,556)	2,709,763	2,452,051	197,703	1,372,897	(257,903)	78,427	136,644	3,864,697
Total Billing kWh for Mohave	46,487,248	38,376,130	40,600,388	41,150,868	50,830,871	73,787,685	97,817,157	85,779,137	70,556,927	51,168,084	43,869,765	45,591,644	686,015,904
AEPCO Base kWh	46,487,248	38,376,130	40,522,483	41,150,868	50,830,871	72,253,340	88,943,711	80,629,302	69,195,434	51,145,199	43,869,765	45,591,644	668,995,995
AEPCO Other kWh	0	0	77,905	0	0	1,534,345	8,744,446	5,149,835	1,361,493	22,885	0	0	16,890,909
Renewable kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
Market kWh	0	0	0	0	0	0	129,000	0	0	0	0	0	129,000
Total	46,487,248	38,376,130	40,600,388	41,150,868	50,830,871	73,787,685	97,817,157	85,779,137	70,556,927	51,168,084	43,869,765	45,591,644	686,015,904
Rate													
Fixed Generation Charge	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	
Fixed Generation O&M Charge	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	
Base kWh Charge	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	0.032150	
Other kWh Charge	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	0.068790	
Estimated Market Price	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	0.060000	
Actual 2010 AEPCA PPFAC	0.011560	0.011560	0.011560	0.020060	0.020060	0.020060	0.020060	0.020060	0.020060	0.020110	0.020110	0.020110	
AEPCO Rate Case PPFAC	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	0.015224	
Calculated PPFAC New Rate	(0.003664)	(0.003664)	(0.003664)	0.004836	0.004836	0.004836	0.004836	0.004836	0.004836	0.004886	0.004886	0.004886	
Base PPFAC kWh Charge	(0.003664)	(0.003664)	(0.003664)	0.004836	0.004836	0.004836	0.004836	0.004836	0.004836	0.004886	0.004886	0.004886	0.003253
Other PPFAC kWh Charge	(0.003664)	(0.003664)	(0.003664)	0.004836	0.004836	0.004836	0.004836	0.004836	0.004836	0.004886	0.004886	0.004886	0.004797
Renewable kWh Charge	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	0.042000	
AEPCO Fixed Network Ser Ch 1	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	2,187,176.00	
2009 Percentage Network 1	25.386002%	25.435800%	25.664823%	25.684682%	25.532196%	24.863126%	25.112839%	25.193156%	24.672934%	24.504537%	24.544334%	24.348578%	
2009 Percentage Network 2	5.611866%	5.458838%	5.202889%	4.984937%	4.967240%	5.283481%	5.118932%	5.007734%	5.761794%	6.049329%	6.146852%	6.423480%	
Total Projected Network 1	30.997868%	30.894638%	30.867713%	30.669618%	30.499436%	30.146607%	30.231771%	30.200890%	30.434728%	30.553866%	30.691185%	30.772058%	
Fixed Network Service Charge 2	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	2,056,562.00	
Total Projected Network 2	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	
WAPA Transmission	1.080	1.080	1.080	1.080	1.080	1.080	1.080	1.080	1.080	1.080	1.080	1.080	
System Control & Dispatch per kW	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	0.245000	
Var Support/Voltage Control per kW	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	
WAPA Ancillary Services	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	0.058000	

MOHAVE ELECTRIC COOPERATIVE, INC.

ADJUSTED 2010 PURCHASED POWER EXCLUDING RESALE (THIRD PARTY SALES)
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billing													
AEPCO Fixed Generation Charge	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	727,283.00	8,727,396.00
AEPCO Fixed Generation O&M Charge	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	1,274,882.00	15,298,584.00
Total Generation Capacity	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	2,002,165.00	24,025,980.00
AEPCO Base Energy	1,494,565.02	1,233,792.58	1,302,797.83	1,323,000.41	1,634,212.50	2,322,944.88	2,859,540.31	2,592,232.06	2,224,633.20	1,644,318.15	1,410,412.94	1,465,771.35	21,508,221.23
AEPCO Other Energy	0.00	0.00	5,359.08	0.00	0.00	105,547.59	601,530.44	354,257.15	93,657.10	1,574.26	0.00	0.00	1,161,925.62
AEPCO Base PPFAC Energy	(170,329.28)	(140,610.14)	(148,474.38)	199,005.60	245,818.09	349,417.15	430,131.79	389,923.30	334,629.12	249,895.44	214,347.67	222,760.77	2,176,515.13
AEPCO Other PPFAC Energy	0.00	0.00	(285.44)	0.00	0.00	7,420.09	42,288.14	24,904.60	6,584.18	111.82	0.00	0.00	81,023.39
Estimated Market Sales	0.00	0.00	0.00	0.00	0.00	0.00	7,740.00	0.00	0.00	0.00	0.00	0.00	7,740.00
Total Generation Energy	1,324,235.74	1,093,182.44	1,159,397.09	1,522,006.01	1,880,030.59	2,785,329.71	3,941,230.68	3,361,317.11	2,659,503.60	1,895,899.67	1,624,760.61	1,688,532.12	24,935,425.37
WAPA Admin Fee	0.00	0.00	0.00	0.00	37,500.00	19,447.44	27,551.78	18,140.14	17,480.80	17,408.09	17,758.95	(43,221.61)	112,065.59
Total AEPCO Generation	3,326,400.74	3,095,347.44	3,161,562.09	3,524,171.01	3,919,695.59	4,806,942.15	5,970,947.46	5,381,622.25	4,679,149.40	3,915,472.76	3,644,684.56	3,647,475.51	49,073,470.96
Renewable Generation Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Generation	3,326,400.74	3,095,347.44	3,161,562.09	3,524,171.01	3,919,695.59	4,806,942.15	5,970,947.46	5,381,622.25	4,679,149.40	3,915,472.76	3,644,684.56	3,647,475.51	49,073,470.96
SWTC Network Transmission 1	677,977.92	675,720.11	675,131.20	670,798.53	667,076.33	659,359.35	661,222.04	660,546.62	665,661.08	668,266.83	671,270.24	673,039.06	8,026,069.31
SWTC Network Transmission 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WAPA Transmission Direct	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	37,800.00	453,600.00
SWTC System Control & Dispatch	19,405.72	18,339.72	17,136.28	22,235.71	29,233.65	41,589.00	46,809.95	42,330.86	40,278.74	32,846.66	19,668.11	21,562.70	351,437.10
SWTC Var Support/Volage Control	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WAPA Ancillary Reactive Power	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	2,030.00	24,360.00
WAPA Ancillary Services Direct	9,205.87	7,620.38	7,996.52	7,760.09	10,007.16	13,971.68	18,745.75	16,826.09	11,813.89	10,193.32	8,681.66	17,827.53	140,649.94
AES Admin Fee	(49.53)	(143.88)	(361.34)	(316.29)	(717.16)	(578.69)	(366.12)	(118.92)	(155.17)	(17.50)	(2.54)	350.42	(2,476.72)
Total Transmission	746,369.98	741,366.33	739,732.66	740,308.04	745,429.98	754,171.34	766,241.62	759,414.65	757,428.54	751,119.31	739,447.47	752,609.71	8,993,639.63
Subtotal Purchased Power	4,072,770.72	3,836,713.77	3,901,294.75	4,264,479.05	4,665,125.57	5,561,113.49	6,737,189.08	6,141,036.90	5,436,577.94	4,666,592.07	4,384,132.03	4,400,085.22	58,067,110.59
Average Cost	0.087610	0.099977	0.096090	0.103630	0.091777	0.075366	0.068875	0.071591	0.077052	0.091201	0.099935	0.096511	0.084644
Own Use kWh	40,243	32,566	38,260	44,238	49,116	80,702	106,691	98,188	69,616	54,015	44,645	45,327	703,607
Own Use	(3,525.71)	(3,255.84)	(3,676.41)	(4,584.40)	(4,507.74)	(6,082.22)	(7,348.38)	(7,029.40)	(5,364.08)	(4,926.23)	(4,461.61)	(4,374.54)	(59,136.56)
Subtotal Purchased Power	4,069,245.01	3,833,457.93	3,897,618.34	4,259,894.65	4,660,617.83	5,555,031.27	6,729,840.70	6,134,007.50	5,431,213.86	4,661,665.84	4,379,670.42	4,395,710.68	58,007,974.03
Other Expenses Acct 557	12,488.77	23,478.46	68,028.92	21,522.54	78,605.81	56,092.39	22,965.48	76,193.38	57,878.19	52,544.53	71,385.83	30,538.37	571,722.67
Total Power Cost	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70

MOHAVE ELECTRIC COOPERATIVE, INC.

ADJUSTED 2010 PURCHASED POWER FOR RESALE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total
kWh													
Total Resale kWh	12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	475,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Rate													
Strike Price	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	0.038980	
Base PPFAC Charge	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	0.003253	
Billing													
Total Power Cost	535,827.74	488,394.61	43,062.54	470,499.99	64,746.00	149,958.54	190.95	20,096.52	60,536.13	398,630.87	487,656.54	503,379.38	3,222,979.80

MOHAVE ELECTRIC COOPERATIVE, INC.

TOTAL ADJUSTED 2010 PURCHASED POWER
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

kWh													
System Remainder	46,842,898	38,713,036	41,692,165	41,529,864	51,492,427	71,077,922	95,365,106	85,581,434	69,184,030	51,425,987	43,791,338	45,455,000	682,151,207
Resale	12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	475,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Total	59,530,195	50,277,214	42,711,797	52,670,334	53,025,479	74,628,631	95,369,627	86,057,278	70,617,401	60,864,744	55,338,040	57,373,986	758,464,727
Billing													
System Remainder	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Resale	535,827.74	488,394.61	43,062.54	470,499.99	64,746.00	149,958.54	190.95	20,096.52	60,536.13	398,630.87	487,656.54	503,379.38	3,222,979.80
Total	4,617,561.52	4,345,331.00	4,008,709.80	4,751,917.18	4,803,969.64	5,761,082.20	6,752,997.13	6,230,297.40	5,549,628.18	5,112,841.24	4,938,712.79	4,929,628.43	61,802,676.50

SUPPLEMENTAL SCHEDULE G
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Supplemental Section G

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SUPPLEMENTAL SCHEDULE H

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES

			kWh		Adjusted	Proposed	Change	
		Cust	Total	Avg Mn	2010	2010	$	%
Residential		34,875	364,970,959	872	42,986,712	44,735,329	1,748,617	4.07%
Irrigation Time of Use		12	1,730,345	12,016	166,306	168,026	1,720	1.03%
Irrigation Pumping		11	2,572,007	19,485	302,194	309,962	7,768	2.57%
Subtotal Irrigation		23	4,302,352	15,588	468,500	477,988	9,488	2.03%
Small Comm Energy		3,201	42,164,591	1,098	4,900,351	5,177,391	277,040	5.65%
Small Comm Demand		529	70,626,268	11,126	7,389,210	7,729,118	339,908	4.60%
Small Comm TOU		8	1,020,044	10,625	96,177	100,936	4,759	4.95%
Subtotal Small Comm		3,738	113,810,903	2,537	12,385,738	13,007,445	621,707	5.02%
Large Comm & Industrial		118	170,994,538	4,495,062	15,775,430	16,108,634	333,204	2.11%
LC&I TOU		3	564,880	15,691	48,035	67,443	19,408	40.40%
Lighting Devices	*	1,151	1,100,103	80	98,025	103,184	5,159	5.26%
Resale	*	1	46,862,961	3,905,247	3,698,667	3,698,667	0	0.00%
Total Energy Sales	*	38,757	702,606,696	1,511	75,461,107	78,198,690	2,737,583	3.63%
Other Revenue					606,899	863,547	256,647	42.29%
Total Revenue					76,068,007	79,062,237	2,994,230	3.94%

** Total Customers excludes Lighting Devices and Resale*

Data From Supplemental Schedules F-4.0 (Adjusted TY) and N-1.0 (Proposed TY)

Supplemental Schedules H-3.0 – H-3.1

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MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES
RESIDENTIAL SERVICE

kWh Usage		Monthly * Cust	Existing Rate	Proposed Rate	Change $	Change %
Service Charge			$9.50	$16.50	$7.00	73.68%
Energy Charge, per kWh						
First	400		$0.083190	$0.096373	$0.013183	15.85%
Next	600		$0.083190	$0.106373	$0.023183	27.87%
Over	1,000		$0.083190	$0.116373	$0.033183	39.89%
PPCA Factor			$0.023685	($0.001850)	($0.025535)	-107.81%
Total Energy Charge plus PPCA						
First	400		$0.106875	$0.094523	($0.012352)	-11.56%
Next	600		$0.106875	$0.104523	($0.002352)	-2.20%
Over	1,000		$0.106875	$0.114523	$0.007648	7.16%
0		1,009	$9.50	$16.50	$7.00	73.68%
100		2,913	$20.19	$25.95	$5.76	28.56%
200		2,687	$30.88	$35.40	$4.53	14.67%
400		5,213	$52.25	$54.31	$2.06	3.94%
800		9,166	$95.00	$96.12	$1.12	1.18%
1,000		3,212	$116.38	$117.02	$0.65	0.56%
2,000		7,881	$223.25	$231.55	$8.30	3.72%
3,000		2,466	$330.13	$346.07	$15.94	4.83%
5,000		738	$543.88	$575.12	$31.24	5.74%
8,000		54	$864.50	$918.68	$54.18	6.27%
Over		4				
860	**Average**		**$101.41**	**$102.39**	**$0.98**	**0.96%**
637	**Median**		**$77.58**	**$79.08**	**$1.50**	**1.94%**

** Customers with usage from the previous block to this block*

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES
OPTIONAL RESIDENTIAL TIME OF USE

kWh Usage	Off Peak kWh	On-Peak kWh		Existing Rate	Proposed Rate No Wknds	Proposed Rate Weekends	Change - $ No Wknds	Change - $ Weekends	Change - % No Wknds	Change - % Weekends
Service Charge				$15.00	$21.50	$21.50	$6.50	$6.50	43.33%	43.33%
Discount on Energy Charges						2.25%				
On-Peak Energy Charge, per kWh										
First	400			$0.149500	$0.208316	$0.203629	$0.058816	$0.054129	39.34%	36.21%
Next	600			$0.149500	$0.218316	$0.213404	$0.068816	$0.063904	46.03%	42.75%
Over	1,000			$0.149500	$0.228316	$0.223179	$0.078816	$0.073679	52.72%	49.28%
Off-Peak Energy Charge, per kWh										
First	400			$0.052000	$0.058316	$0.057004	$0.006316	$0.005004	12.15%	9.62%
Next	600			$0.052000	$0.068316	$0.066779	$0.016316	$0.014779	31.38%	28.42%
Over	1,000			$0.052000	$0.078316	$0.076554	$0.026316	$0.024554	50.61%	47.22%
PPCA Factor				$0.023685	($0.001850)	($0.001850)	($0.025535)	($0.025535)	-107.81%	-107.81%
250	250	0	0%	$33.92	$35.62	$35.29	$1.70	$1.37	5.00%	4.03%
500	500	0	0%	$52.84	$50.73	$50.05	($2.11)	($2.79)	-3.99%	-5.28%
893	893	0	0%	$82.59	$76.85	$75.57	($5.73)	($7.02)	-6.94%	-8.49%
1,000	1,000	0	0%	$90.69	$83.97	$82.52	($6.72)	($8.17)	-7.41%	-9.00%
1,500	1,500	0	0%	$128.53	$122.20	$119.87	($6.33)	($8.66)	-4.92%	-6.74%
3,000	3,000	0	0%	$242.06	$236.90	$231.93	($5.16)	($10.13)	-2.13%	-4.18%
250	212	38	15%	$37.63	$41.32	$40.86	$3.69	$3.23	9.81%	8.60%
500	425	75	15%	$60.16	$61.98	$61.05	$1.83	$0.90	3.04%	1.49%
893	759	134	15%	$95.65	$96.95	$95.22	$1.30	($0.43)	1.36%	-0.45%
1,000	850	150	15%	$105.31	$106.47	$104.51	$1.16	($0.80)	1.10%	-0.76%
1,500	1,275	225	15%	$150.47	$155.95	$152.86	$5.48	$2.40	3.64%	1.59%
3,000	2,550	450	15%	$285.93	$304.40	$297.91	$18.47	$11.98	6.46%	4.19%
250	182	68	27%	$40.55	$45.82	$45.26	$5.27	$4.71	12.98%	11.61%
500	365	135	27%	$66.01	$70.98	$69.85	$4.98	$3.84	7.54%	5.82%
893	652	241	27%	$106.08	$113.00	$110.91	$6.92	$4.82	6.52%	4.55%
1,000	730	270	27%	$117.01	$124.47	$122.11	$7.46	$5.10	6.37%	4.36%
1,500	1,095	405	27%	$168.02	$182.95	$179.25	$14.93	$11.24	8.89%	6.69%
3,000	2,190	810	27%	$321.03	$358.40	$350.69	$37.37	$29.66	11.64%	9.24%
250	100	150	60%	$48.55	$58.12	$57.28	$9.57	$8.74	19.71%	18.00%
500	200	300	60%	$82.09	$95.73	$94.04	$13.64	$11.95	16.62%	14.56%
893	357	536	60%	$134.85	$157.25	$154.16	$22.41	$19.32	16.62%	14.32%
1,000	400	600	60%	$149.19	$173.97	$170.49	$24.78	$21.31	16.61%	14.28%
1,500	600	900	60%	$216.28	$257.20	$251.83	$40.92	$35.56	18.92%	16.44%
3,000	1,200	1,800	60%	$417.56	$506.90	$495.85	$89.34	$78.30	21.40%	18.75%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES
EXPERIMENTAL RESIDENTIAL DEMAND SERVICE

kWh Usage	kW	L.F.	Existing Rate	Proposed Rate	Change $	Change %
Service Charge			$13.50	$21.50	$8.00	59.26%
Demand Charge, per NCP kW			$7.50	$8.50	$1.00	13.33%
Energy Charge, per kWh						
First	400		$0.048000	$0.068402	$0.020402	42.50%
Next	600		$0.048000	$0.077467	$0.029467	61.39%
Over	1,000		$0.048000	$0.087467	$0.039467	82.22%
PPCA Factor			$0.023685	($0.001850)	($0.025535)	-107.81%
110	1.50	10%	$32.64	$41.57	$8.94	27.38%
329	1.50	30%	$48.33	$56.15	$7.81	16.16%
548	1.50	50%	$64.03	$72.06	$8.03	12.54%
767	1.50	70%	$79.73	$88.62	$8.89	11.15%
986	1.50	90%	$95.43	$105.18	$9.75	10.22%
219	3.00	10%	$51.70	$61.57	$9.88	19.10%
657	3.00	30%	$83.10	$93.05	$9.96	11.98%
1,095	3.00	50%	$114.50	$127.12	$12.63	11.03%
1,533	3.00	70%	$145.89	$164.62	$18.73	12.84%
1,971	3.00	90%	$177.29	$202.13	$24.83	14.01%
365	5.00	10%	$77.17	$88.29	$11.13	14.42%
1,095	5.00	30%	$129.50	$144.12	$14.63	11.30%
1,825	5.00	50%	$181.83	$206.63	$24.80	13.64%
2,555	5.00	70%	$234.16	$269.13	$34.97	14.93%
3,285	5.00	90%	$286.49	$331.63	$45.14	15.76%
1,095	15.00	10%	$204.50	$229.12	$24.63	12.04%
3,285	15.00	30%	$361.49	$416.63	$55.14	15.25%
5,475	15.00	50%	$518.48	$604.13	$85.65	16.52%
7,665	15.00	70%	$675.47	$791.63	$116.16	17.20%
9,855	15.00	90%	$832.46	$979.13	$146.67	17.62%
3,650	50.00	10%	$650.15	$745.38	$95.23	14.65%
10,950	50.00	30%	$1,173.45	$1,370.38	$196.93	16.78%
18,250	50.00	50%	$1,696.75	$1,995.38	$298.63	17.60%
25,550	50.00	70%	$2,220.05	$2,620.39	$400.34	18.03%
32,850	50.00	90%	$2,743.35	$3,245.39	$502.04	18.30%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES
IRRIGATION

Load Factor	NCP Demand	kWh Usage	Existing Rate	Proposed Rate	Change $	Change %
Service Charge			$60.00	$60.00	$0.00	0.00%
Demand Charge			$7.00	$7.53	$0.53	7.57%
Energy Charge, per kWh			$0.058000	$0.084077	$0.026077	44.96%
PPCA Factor			$0.023685	($0.001850)	($0.025535)	-107.81%
Total Energy Charge plus PPCA						
Energy Charge, per kWh			$0.081685	$0.082227	$0.000542	0.66%
50.9%	943.70	350,880	$35,987.53	$36,677.87	$690.34	1.92%
47.1%	727.97	250,159	$26,250.03	$26,771.44	$521.41	1.99%
47.0%	552.69	189,548	$20,072.06	$20,467.72	$395.66	1.97%
45.8%	503.96	168,496	$18,011.32	$18,369.74	$358.42	1.99%
42.8%	363.00	113,471	$12,529.88	$12,783.77	$253.89	2.03%
36.8%	452.49	121,511	$13,813.06	$14,118.73	$305.68	2.21%
23.3%	587.20	100,080	$13,005.43	$13,370.89	$365.46	2.81%
25.9%	375.65	71,139	$9,160.54	$9,398.19	$237.65	2.59%
31.2%	2,503.20	570,320	$64,828.99	$66,464.80	$1,635.81	2.52%
19.5%	1,841.60	262,480	$35,051.88	$36,170.19	$1,118.31	3.19%
16.1%	3,182.40	373,920	$53,540.46	$55,429.79	$1,889.34	3.53%
Total	12,033.86	2,572,004	$302,251.17	$310,023.14	$7,771.97	2.57%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES
IRRIGATION TIME OF USE

Load Factor	NCP Demand	Peak Demand	kWh Usage	Existing Rate	Proposed Rate	Change $	Change %
Service Charge				$60.00	$65.00	$5.00	8.33%
On Peak Demand Charge				$13.50	$8.90	($4.60)	-34.07%
Demand Charge				$0.00	$1.63	$1.63	0.00%
Energy Charge, per kWh				$0.050000	$0.074077	$0.024077	48.15%
PPCA Factor				$0.023685	($0.001850)	($0.025535)	-107.81%
Total Energy Charge plus PPCA							
Energy Charge, per kWh				$0.073685	$0.072227	($0.001458)	-1.98%
15.6%	1,144.80	-	130,200	$10,313.79	$12,049.98	$1,736.19	16.83%
49.8%	516.42	79.24	187,756	$15,624.54	$15,888.05	$263.51	1.69%
14.5%	796.00	-	84,480	$6,944.91	$8,179.22	$1,234.31	17.77%
64.3%	449.59	155.46	210,913	$18,359.83	$18,130.04	($229.80)	-1.25%
14.6%	819.20	0	87,160	$7,142.38	$8,410.60	$1,268.22	17.76%
14.5%	831.20	-	88,080	$7,210.17	$8,496.61	$1,286.44	17.84%
49.0%	730.40	321.60	261,120	$24,302.23	$23,692.71	($609.52)	-2.51%
13.1%	772.80	9.20	73,840	$6,285.10	$7,454.79	$1,169.69	18.61%
50.7%	424.00	-	156,800	$12,273.81	$12,796.31	$522.51	4.26%
41.4%	1,367.20	960.00	412,960	$44,108.96	$41,379.40	($2,729.56)	-6.19%
3.1%	181.03	120.05	4,050	$2,639.10	$2,436.04	($203.06)	-7.69%
7.6%	434.17	588.94	24,241	$10,456.89	$8,480.12	($1,976.77)	-18.90%
Total	8,466.81	2,234.49	1,721,600	$165,661.71	$167,393.86	$1,732.15	1.05%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
SMALL COMMERCIAL - ENERGY

kWh Usage	Monthly * Cust	Existing Rate	Proposed Rate	Change $	Change %
Service Charge		$12.00	$21.50	$9.50	79.17%
Energy Charge, per kWh		$0.081600	$0.105039	$0.023439	28.72%
PPCA Factor		$0.023685	($0.001850)	($0.025535)	-107.81%
Total Energy Charge plus PPCA					
		$0.105285	$0.103189	($0.002096)	-1.99%
0	187	$12.00	$21.50	$9.50	79.17%
100	353	$22.53	$31.82	$9.29	41.24%
200	262	$33.06	$42.14	$9.08	27.47%
400	442	$54.11	$62.78	$8.66	16.01%
800	613	$96.23	$104.05	$7.82	8.13%
1,000	211	$117.29	$124.69	$7.40	6.31%
2,000	599	$222.57	$227.88	$5.31	2.38%
3,000	276	$327.86	$331.07	$3.21	0.98%
5,000	216	$538.43	$537.45	($0.98)	-0.18%
8,000	70	$854.28	$847.01	($7.27)	-0.85%
Over	13				
1,093 Average		**$127.08**	**$134.29**	**$7.21**	**5.67%**
686 Median		**$84.23**	**$92.29**	**$8.06**	**9.57%**

** Customers with usage from the previous block to this block*

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
SMALL COMMERCIAL - DEMAND

Load Factor	Billing kW	kWh	Existing Rate	Proposed Rate	Change $	Change %
Customer Charge			$25.00	$35.00	$10.00	40.00%
Demand Charge, per Billing kW > 3 kW			$8.25	$10.79	$2.54	30.79%
Energy Charge, per kWh			$0.053740	$0.075507	$0.021767	40.50%
PPCA Factor			$0.023685	($0.001850)	($0.025535)	-107.81%
Total Energy Charge plus PPCA						
Energy Charge, per kWh			$0.077425	$0.073657	($0.003768)	-4.87%
20%	15.00	2,190	$318.31	$358.16	$39.85	12.52%
40%	15.00	4,380	$487.87	$519.47	$31.60	6.48%
60%	15.00	6,570	$657.43	$680.78	$23.34	3.55%
80%	15.00	8,760	$826.99	$842.09	$15.09	1.82%
20%	50.00	7,300	$1,002.70	$1,112.20	$109.49	10.92%
40%	50.00	14,600	$1,567.91	$1,649.89	$81.99	5.23%
60%	50.00	21,900	$2,133.11	$2,187.59	$54.48	2.55%
80%	50.00	29,200	$2,698.31	$2,725.28	$26.97	1.00%
20%	500.00	73,000	$9,802.03	$10,806.96	$1,004.94	10.25%
40%	500.00	146,000	$15,454.05	$16,183.92	$729.87	4.72%
60%	500.00	219,000	$21,106.08	$21,560.88	$454.81	2.15%
80%	500.00	292,000	$26,758.10	$26,937.84	$179.74	0.67%
20%	1,000.00	146,000	$19,579.05	$21,578.92	$1,999.87	10.21%
40%	1,000.00	292,000	$30,883.10	$32,332.84	$1,449.74	4.69%
60%	1,000.00	438,000	$42,187.15	$43,086.77	$899.62	2.13%
80%	1,000.00	584,000	$53,491.20	$53,840.69	$349.49	0.65%
46%	33.69	11,351	$1,181.79	$1,234.60	$52.80	4.47%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
SMALL COMMERCIAL - TIME OF USE

Load Factor	Estimated On-Peak *		Billing kW	kWh	Existing Rate	Proposed Rate	Change $	Change %
Customer Charge					$30.00	$40.00	$10.00	33.33%
On Peak Demand Charge					$12.50	$15.00		
NCP Demand Charge					$0.00	$4.48	$4.48	#DIV/0!
Energy Charge, per kWh					$0.050400	$0.062256	$0.011856	23.52%
PPCA Factor					$0.023685	($0.001850)	($0.025535)	-107.81%
20%	-	0%	15.00	2,190	$192.25	$239.49	$47.24	24.57%
40%	-	0%	15.00	4,380	$354.49	$371.78	$17.29	4.88%
60%	-	0%	15.00	6,570	$516.74	$504.07	($12.67)	-2.45%
80%	-	0%	15.00	8,760	$678.98	$636.36	($42.63)	-6.28%
20%	5.00	10%	50.00	7,300	$633.32	$779.96	$146.64	23.15%
40%	5.00	10%	50.00	14,600	$1,174.14	$1,220.93	$46.79	3.98%
60%	5.00	10%	50.00	21,900	$1,714.96	$1,661.89	($53.07)	-3.09%
80%	5.00	10%	50.00	29,200	$2,255.78	$2,102.86	($152.93)	-6.78%
20%	250.00	50%	500.00	73,000	$8,563.21	$10,439.64	$1,876.43	21.91%
40%	250.00	50%	500.00	146,000	$13,971.41	$14,849.28	$877.87	6.28%
60%	250.00	50%	500.00	219,000	$19,379.62	$19,258.91	($120.70)	-0.62%
80%	250.00	50%	500.00	292,000	$24,787.82	$23,668.55	($1,119.27)	-4.52%
20%	1,000.00	100%	1,000.00	146,000	$23,346.41	$28,339.28	$4,992.87	21.39%
40%	1,000.00	100%	1,000.00	292,000	$34,162.82	$37,158.55	$2,995.73	8.77%
60%	1,000.00	100%	1,000.00	438,000	$44,979.23	$45,977.83	$998.60	2.22%
80%	1,000.00	100%	1,000.00	584,000	$55,795.64	$54,797.10	($998.54)	-1.79%
44%	15.72	45%	34.90	11,209	$1,056.92	$1,109.24	$52.32	4.95%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
LARGE COMMERCIAL & INDUSTRIAL

L.F.	Billing kW	kWh	Existing Rate	Proposed Rate	Change $	Change %
Customer Charge			$70.00	$170.00	$100.00	142.86%
Demand Charge, per Billing kW			$9.75	$10.75	$1.00	10.26%
Energy Charge, per kWh			$0.045580	$0.072288	$0.026708	58.60%
Discount on Dem & Ener - Subtransm			0%	-7.50%		
Discount on Dem & Ener - Substation			0%	-5.00%		
Discount on Dem & Ener - Dist Primary			0%	-1.00%		
PPCA Factor			$0.023685	($0.001850)	($0.025535)	
20%	25.00	3,650	$566.57	$695.85	$129.28	22.82%
40%	25.00	7,300	$819.38	$952.95	$133.56	16.30%
60%	25.00	10,950	$1,072.20	$1,210.05	$137.84	12.86%
80%	25.00	14,600	$1,325.02	$1,467.14	$142.13	10.73%
20%	500.00	73,000	$10,001.35	$10,686.97	$685.63	6.86%
40%	500.00	146,000	$15,057.69	$15,828.95	$771.26	5.12%
60%	500.00	219,000	$20,114.04	$20,970.92	$856.89	4.26%
80%	500.00	292,000	$25,170.38	$26,112.90	$942.52	3.74%
20%	1,000.00	146,000	$19,932.69	$21,203.95	$1,271.26	6.38%
40%	1,000.00	292,000	$30,045.38	$31,487.90	$1,442.52	4.80%
60%	1,000.00	438,000	$40,158.07	$41,771.84	$1,613.77	4.02%
80%	1,000.00	584,000	$50,270.76	$52,055.79	$1,785.03	3.55%
20%	5,000.00	730,000	$99,383.45	$105,339.74	$5,956.29	5.99%
40%	5,000.00	1,460,000	$149,946.90	$156,759.48	$6,812.58	4.54%
60%	5,000.00	2,190,000	$200,510.35	$208,179.22	$7,668.87	3.82%
80%	5,000.00	2,920,000	$251,073.80	$259,598.96	$8,525.16	3.40%
55%	192.64	77,631	$7,325.35	$7,709.05	$383.70	5.24%
Primary Level						
68%	477.00	236,037	$21,069.83	$21,923.70	$853.87	4.05%
Substation Level						
79%	2,812.50	1,616,750	$139,476.06	$136,929.71	($2,546.35)	-1.83%
Subtransmission Level (Note: Currently billed under LP TOU Rate)						
78%	4,425.50	2,517,000	$217,558.63	$207,822.34	($9,736.29)	-4.48%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
LARGE COMMERCIAL & IND TIME OF USE

L.F.	Estimated On-Peak *		NCP kW	kWh	Existing Rate Standard	Existing Rate TOU	Existing Rate TOU Lower	Proposed Rate Standard	Proposed Rate TOU	Proposed Rate TOU Lower
Customer Charge					$70.00	$70.00		$170.00	$175.00	
On Peak Demand Charge, per on peak kW						$13.50			$23.00	
Demand Charge, per NCP kW					$9.75			$10.75	$2.99	
Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276	
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000	
20%	-	0%	300.00	43,800	$6,029	$2,903	$3,126	$6,561	$3,405	$3,156
40%	-	0%	300.00	87,600	$9,063	$5,736	$3,326	$9,727	$5,739	$3,988
60%	-	0%	300.00	131,400	$12,096	$8,570	$3,527	$12,894	$8,072	$4,821
80%	-	0%	300.00	175,200	$15,130	$11,403	$3,727	$16,060	$10,406	$5,654
20%	100.00	10%	1,000.00	146,000	$19,933	$10,864	$9,069	$21,474	$13,243	$8,231
40%	100.00	10%	1,000.00	292,000	$30,045	$20,308	$9,737	$32,028	$21,022	$11,007
60%	100.00	10%	1,000.00	438,000	$40,158	$29,752	$10,406	$42,582	$28,800	$13,782
80%	100.00	10%	1,000.00	584,000	$50,271	$39,196	$11,075	$53,136	$36,578	$16,558
20%	2,500.00	50%	5,000.00	730,000	$99,383	$81,040	$18,343	$106,690	$111,516	$0
40%	2,500.00	50%	5,000.00	1,460,000	$149,947	$128,260	$21,687	$159,460	$150,408	$9,053
60%	2,500.00	50%	5,000.00	2,190,000	$200,510	$175,480	$25,030	$212,231	$189,299	$22,931
80%	2,500.00	50%	5,000.00	2,920,000	$251,074	$222,700	$28,374	$265,001	$228,191	$36,810
20%	10,000.00	100%	10,000.00	1,460,000	$198,697	$229,510	$0	$213,210	$337,858	$0
40%	10,000.00	100%	10,000.00	2,920,000	$299,824	$323,950	$0	$318,751	$415,641	$0
60%	10,000.00	100%	10,000.00	4,380,000	$400,951	$418,390	$0	$424,291	$493,424	$0
80%	10,000.00	100%	10,000.00	5,840,000	$502,078	$512,830	$0	$529,832	$571,207	$0

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
LIGHTING

Lamp		Qty	Existing Billing	Proposed Billing			Change	
				Base	PPCA	Total	$	%
175 W MVL	100 kWh per month	525	$6.85	$7.32	($0.19)	$7.13	$0.28	4.09%
100 W HPS	50 kWh per month	222	$7.88	$8.42	($0.09)	$8.33	$0.45	5.71%
175 W MVL CO	100 kWh per month	27	$5.11	$6.49	($0.19)	$6.30	$1.19	23.29%
100 W HPS CO	50 kWh per month	307	$5.11	$5.46	($0.09)	$5.37	$0.26	5.09%
250 W HPS	129 kWh per month	102	$13.18	$14.09	($0.24)	$13.85	$0.67	5.08%

* CO = Customer Owned

MOHAVE ELECTRIC COOPERATIVE, INC.

SUMMARY OF BILL FREQUENCY REPORT
SEE SUPPLEMENTAL SECTION K FOR DETAIL INFORMATION BY RATE CLASS BY BLOCK

		2010 Cust from Bill Frequency			2010 Adj Customers		2010 KWh Sales		
		Total	Average	Median	Total	Avg Mn	Total	Average	Median
Residential		424,142	35,345	17,673	418,494	34,875	364,970,959	860	637
Irrigation Time of Use		192	16	8	144	12	1,730,345	9,012	5,687
Irrigation Pumping		132	11	6	132	11	2,572,007	19,485	13,534
Small Com Energy		38,565	3,214	1,607	38,372	3,201	42,164,591	1,093	686
Small Com Demand		6,371	531	265	6,336	529	70,626,268	11,086	9,426
Small Com TOU		123	10	5	91	8	1,020,044	8,293	11,290
Large Com & Industrial		1,420	118	59	1,417	118	170,994,538	120,419	46,200
LC&I TOU		43	4	2	31	3	564,880	13,137	14,990
Lighting Devices	*						1,100,103		
Resale	*						46,862,961		
Total Energy Sales	*	470,988	39,249	19,625	465,017	38,757	702,606,696	183,385	102,450

See Supplemental Section K for Detailed Information by Rate Class by Energy Block

MOHAVE ELECTRIC COOPERATIVE, INC.

2010 Revenue Under Existing Rates - See Supplemental Schedule F-4.0

2010 Revenue Under Proposed Rates - See Supplemental Schedule N-1.0

Schedule shows for each rate class:

Billing units
Rate Applied
Calculation of Revenue

SUPPLEMENTAL SCHEDULES I – J
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Supplemental Sections I through J

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SUPPLEMENTAL SCHEDULE K

Supplemental Section K

Detailed Bill Frequency Data for 2010

Mohave Electric Cooperative, Inc.
Residential (101,102,105,109)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block: Bills Each Block	Bills Accumulated	Percentage Each Block	Percentage Accumulated	Energy Ending In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated	Energy In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated
0	0	12,109	12,109	2.85	2.85	0	0	0.00	0.00	0	0	0.00	0.00
1	10	4,480	16,589	1.06	3.91	19,945	19,945	0.01	0.01	4,095,475	4,095,475	1.12	1.12
11	20	3,440	20,029	0.81	4.72	54,073	74,018	0.01	0.02	4,060,803	8,156,278	1.11	2.24
21	30	3,367	23,396	0.79	5.52	85,560	159,578	0.02	0.04	4,025,680	12,181,958	1.11	3.34
31	40	3,099	26,495	0.73	6.25	109,707	269,285	0.03	0.07	3,993,207	16,175,165	1.10	4.44
41	50	3,113	29,608	0.73	6.98	141,863	411,148	0.04	0.11	3,962,683	20,137,848	1.09	5.53
51	60	3,296	32,904	0.78	7.76	183,071	594,219	0.05	0.16	3,930,651	24,068,499	1.08	6.61
61	70	3,505	36,409	0.83	8.58	229,742	823,961	0.06	0.23	3,896,772	27,965,271	1.07	7.68
71	80	3,489	39,898	0.82	9.41	263,571	1,087,532	0.07	0.30	3,861,781	31,827,052	1.06	8.74
81	90	3,604	43,502	0.85	10.26	308,306	1,395,838	0.08	0.38	3,826,386	35,653,438	1.05	9.79
91	100	3,568	47,070	0.84	11.10	340,934	1,736,772	0.09	0.48	3,790,534	39,443,972	1.04	10.83
101	200	32,244	79,314	7.60	18.70	4,799,712	6,536,484	1.32	1.79	36,058,112	75,502,084	9.90	20.73
201	300	30,542	109,856	7.20	25.90	7,662,237	14,198,721	2.10	3.90	32,982,437	108,484,521	9.06	29.79
301	400	32,014	141,870	7.55	33.45	11,222,872	25,421,593	3.08	6.98	29,845,872	138,330,393	8.19	37.98
401	500	31,486	173,356	7.42	40.87	14,170,985	39,592,578	3.89	10.87	26,655,185	164,985,578	7.32	45.30
501	600	29,091	202,447	6.86	47.73	15,986,574	55,579,152	4.39	15.26	23,610,574	188,596,152	6.48	51.78
601	700	26,212	228,659	6.18	53.91	17,019,830	72,598,982	4.67	19.93	20,840,930	209,437,082	5.72	57.50
701	800	23,206	251,865	5.47	59.38	17,393,203	89,992,185	4.78	24.71	18,376,703	227,813,785	5.05	62.55
801	900	20,554	272,419	4.85	64.23	17,458,212	107,450,397	4.79	29.50	16,187,312	244,001,097	4.44	66.99
901	1,000	17,991	290,410	4.24	68.47	17,083,542	124,533,939	4.69	34.19	14,264,842	258,265,939	3.92	70.91
1,001	2,000	94,576	384,986	22.30	90.77	132,862,441	257,396,380	36.48	70.67	77,442,441	335,708,380	21.26	92.17
2,001	3,000	29,595	414,581	6.98	97.75	70,991,760	328,388,140	19.49	90.16	21,362,760	357,071,140	5.87	98.04
3,001	4,000	7,241	421,822	1.71	99.45	24,491,068	352,879,208	6.72	96.89	5,088,068	362,159,208	1.40	99.43
4,001	5,000	1,620	423,442	0.38	99.83	7,103,969	359,983,177	1.95	98.84	1,323,969	363,483,177	0.36	99.80
5,001	6,000	436	423,878	0.10	99.94	2,356,339	362,339,516	0.65	99.48	440,339	363,923,516	0.12	99.92
6,001	7,000	161	424,039	0.04	99.98	1,033,455	363,372,971	0.28	99.77	170,455	364,093,971	0.05	99.97
7,001	8,000	55	424,094	0.01	99.99	408,208	363,781,179	0.11	99.88	71,208	364,165,179	0.02	99.98
8,001	9,000	27	424,121	0.01	100.00	229,228	364,010,407	0.06	99.94	34,228	364,199,407	0.01	99.99
9,001	10,000	12	424,133	0.00	100.00	113,619	364,124,026	0.03	99.97	14,619	364,214,026	0.00	100.00
10,001	& Above	9	424,142	0.00	100.00	97,168	364,221,194	0.03	100.00	7,168	364,221,194	0.00	100.00
Accounts with Credits		109	424,251			-19,076	364,202,118						

Average kWh per Customer: 858.72 Average kWh per Customer including Credit Accounts: 858.46

Includes Rates 101, 102, 109

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Residential (101)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block: Bills Each Block	Bills Ending In Block: Bills Accum-ulated	Bills Ending In Block: Percentage Each Block	Bills Ending In Block: Percentage Accum-ulated	Energy Ending In Block: kWh Each Block	Energy Ending In Block: kWh Accum-ulated	Energy Ending In Block: Percentage Each Block	Energy Ending In Block: Percentage Accum-ulated	Energy In Block: kWh Each Block	Energy In Block: kWh Accum-ulated	Energy In Block: Percentage Each Block	Energy In Block: Percentage Accum-ulated
0	0	12,100	12,100	2.86	2.86	0	0	0.00	0.00	0	0	0.00	0.00
1	10	4,479	16,579	1.06	3.91	19,944	19,944	0.01	0.01	4,092,284	4,092,284	1.12	1.12
11	20	3,440	20,019	0.81	4.72	54,073	74,017	0.01	0.02	4,057,613	8,149,897	1.11	2.24
21	30	3,367	23,386	0.79	5.52	85,560	159,577	0.02	0.04	4,022,490	12,172,387	1.11	3.34
31	40	3,099	26,485	0.73	6.25	109,707	269,284	0.03	0.07	3,990,017	16,162,404	1.10	4.44
41	50	3,113	29,598	0.73	6.98	141,863	411,147	0.04	0.11	3,959,493	20,121,897	1.09	5.53
51	60	3,295	32,893	0.78	7.76	183,012	594,159	0.05	0.16	3,927,462	24,049,359	1.08	6.61
61	70	3,501	36,394	0.83	8.59	229,475	823,634	0.06	0.23	3,893,605	27,942,964	1.07	7.68
71	80	3,486	39,880	0.82	9.41	263,348	1,086,982	0.07	0.30	3,858,658	31,801,622	1.06	8.74
81	90	3,601	43,481	0.85	10.26	308,050	1,395,032	0.08	0.38	3,823,290	35,624,912	1.05	9.79
91	100	3,563	47,044	0.84	11.10	340,463	1,735,495	0.09	0.48	3,787,483	39,412,395	1.04	10.83
101	200	32,210	79,254	7.60	18.70	4,794,342	6,529,837	1.32	1.79	36,029,242	75,441,637	9.90	20.73
201	300	30,495	109,749	7.20	25.90	7,650,268	14,180,105	2.10	3.90	32,957,668	108,399,305	9.05	29.78
301	400	31,971	141,720	7.54	33.44	11,207,749	25,387,854	3.08	6.97	29,825,749	138,225,054	8.19	37.97
401	500	31,446	173,166	7.42	40.86	14,152,882	39,540,736	3.89	10.86	26,639,182	164,864,236	7.32	45.29
501	600	29,066	202,232	6.86	47.72	15,972,883	55,513,619	4.39	15.25	23,597,983	188,462,219	6.48	51.78
601	700	26,199	228,431	6.18	53.90	17,011,437	72,525,056	4.67	19.92	20,830,237	209,292,456	5.72	57.50
701	800	23,192	251,623	5.47	59.37	17,382,623	89,907,679	4.78	24.70	18,367,223	227,659,679	5.05	62.54
801	900	20,546	272,169	4.85	64.22	17,451,414	107,359,093	4.79	29.49	16,179,014	243,838,693	4.44	66.99
901	1,000	17,983	290,152	4.24	68.46	17,076,047	124,435,140	4.69	34.19	14,257,447	258,096,140	3.92	70.91
1,001	2,000	94,521	384,673	22.30	90.76	132,781,578	257,216,718	36.48	70.66	77,400,578	335,496,718	21.26	92.17
2,001	3,000	29,580	414,253	6.98	97.74	70,956,306	328,173,024	19.49	90.16	21,356,306	356,853,024	5.87	98.04
3,001	4,000	7,241	421,494	1.71	99.45	24,491,068	352,664,092	6.73	96.89	5,087,068	361,940,092	1.40	99.43
4,001	5,000	1,619	423,113	0.38	99.83	7,099,939	359,764,031	1.95	98.84	1,323,939	363,264,031	0.36	99.80
5,001	6,000	436	423,549	0.10	99.94	2,356,339	362,120,370	0.65	99.48	440,339	363,704,370	0.12	99.92
6,001	7,000	161	423,710	0.04	99.98	1,033,455	363,153,825	0.28	99.77	170,455	363,874,825	0.05	99.97
7,001	8,000	55	423,765	0.01	99.99	408,208	363,562,033	0.11	99.88	71,208	363,946,033	0.02	99.98
8,001	9,000	27	423,792	0.01	100.00	229,228	363,791,261	0.06	99.94	34,228	363,980,261	0.01	99.99
9,001	10,000	12	423,804	0.00	100.00	113,619	363,904,880	0.03	99.97	14,619	363,994,880	0.00	100.00
10,001	& Above	9	423,813	0.00	100.00	97,168	364,002,048	0.03	100.00	7,168	364,002,048	0.00	100.00
Accounts with Credits		109	423,922			-19,076	363,982,972						

Average kWh per Customer: 858.87 Average kWh per Customer including Credit Accounts: 858.61

Rate 101

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Residential Seasonal 102)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block: Bills Each Block	Bills Accumulated	Percentage Each Block	Percentage Accumulated	Energy Ending In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated	Energy in Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated
0	0	9	9	81.82	81.82	0	0	0.00	0.00	0	0	0.00	0.00
1	10	1	10	9.09	90.91	1	1	0.18	0.18	11	11	2.00	2.00
11	20	0	10	0.00	90.91	0	1	0.00	0.18	10	21	1.82	3.83
21	30	0	10	0.00	90.91	0	1	0.00	0.18	10	31	1.82	5.65
31	40	0	10	0.00	90.91	0	1	0.00	0.18	10	41	1.82	7.47
41	50	0	10	0.00	90.91	0	1	0.00	0.18	10	51	1.82	9.29
51	60	0	10	0.00	90.91	0	1	0.00	0.18	10	61	1.82	11.11
61	70	0	10	0.00	90.91	0	1	0.00	0.18	10	71	1.82	12.93
71	80	0	10	0.00	90.91	0	1	0.00	0.18	10	81	1.82	14.75
81	90	0	10	0.00	90.91	0	1	0.00	0.18	10	91	1.82	16.58
91	100	0	10	0.00	90.91	0	1	0.00	0.18	10	101	1.82	18.40
101	200	0	10	0.00	90.91	0	1	0.00	0.18	100	201	18.21	36.61
201	300	0	10	0.00	90.91	0	1	0.00	0.18	100	301	18.21	54.83
301	400	0	10	0.00	90.91	0	1	0.00	0.18	100	401	18.21	73.04
401	500	0	10	0.00	90.91	0	1	0.00	0.18	100	501	18.21	91.26
501	600	1	11	9.09	100.00	548	549	99.82	100.00	48	549	8.74	100.00
601	700	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
701	800	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
801	900	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
901	1,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
1,001	2,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
2,001	3,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
3,001	4,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
4,001	5,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
5,001	6,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
6,001	7,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
7,001	8,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
8,001	9,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
9,001	10,000	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
10,001	& Above	0	11	0.00	100.00	0	549	0.00	100.00	0	549	0.00	100.00
Accounts with Credits		0	11			0	549						

Average kWh per Customer: 49.91 Average kWh per Customer including Credit Accounts: 49.91

Rate 102

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Residential Gov (109)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block: Bills Each Block	Bills Accumulated	Bills Percentage Each Block	Bills Percentage Accumulated	Energy Ending In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated	Energy In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated
0	0	0	0	0.00	0.00	0	0	0.00	0.00	0	0	0.00	0.00
1	10	0	0	0.00	0.00	0	0	0.00	0.00	3,180	3,180	1.45	1.45
11	20	0	0	0.00	0.00	0	0	0.00	0.00	3,180	6,360	1.45	2.91
21	30	0	0	0.00	0.00	0	0	0.00	0.00	3,180	9,540	1.45	4.36
31	40	0	0	0.00	0.00	0	0	0.00	0.00	3,180	12,720	1.45	5.82
41	50	0	0	0.00	0.00	0	0	0.00	0.00	3,180	15,900	1.45	7.27
51	60	1	1	0.31	0.31	59	59	0.03	0.03	3,179	19,079	1.45	8.73
61	70	4	5	1.26	1.57	267	326	0.12	0.15	3,157	22,236	1.44	10.17
71	80	3	8	0.94	2.52	223	549	0.10	0.25	3,113	25,349	1.42	11.60
81	90	3	11	0.94	3.46	256	805	0.12	0.37	3,086	28,435	1.41	13.01
91	100	5	16	1.57	5.03	471	1,276	0.22	0.58	3,041	31,476	1.39	14.40
101	200	34	50	10.69	15.72	5,370	6,646	2.46	3.04	28,770	60,246	13.16	27.56
201	300	47	97	14.78	30.50	11,969	18,615	5.48	8.52	24,669	84,915	11.29	38.85
301	400	43	140	13.52	44.03	15,123	33,738	6.92	15.43	20,023	104,938	9.16	48.01
401	500	40	180	12.58	56.60	18,103	51,841	8.28	23.72	15,903	120,841	7.28	55.28
501	600	24	204	7.55	64.15	13,143	64,984	6.01	29.73	12,543	133,384	5.74	61.02
601	700	13	217	4.09	68.24	8,393	73,377	3.84	33.57	10,693	144,077	4.89	65.91
701	800	14	231	4.40	72.64	10,580	83,957	4.84	38.41	9,480	153,557	4.34	70.25
801	900	8	239	2.52	75.16	6,798	90,755	3.11	41.52	8,298	161,855	3.80	74.04
901	1,000	8	247	2.52	77.67	7,495	98,250	3.43	44.95	7,395	169,250	3.38	77.43
1,001	2,000	55	302	17.30	94.97	80,863	179,113	36.99	81.94	41,863	211,113	19.15	96.58
2,001	3,000	15	317	4.72	99.69	35,454	214,567	16.22	98.16	6,454	217,567	2.95	99.53
3,001	4,000	0	317	0.00	99.69	0	214,567	0.00	98.16	1,000	218,567	0.46	99.99
4,001	5,000	1	318	0.31	100.00	4,030	218,597	1.84	100.00	30	218,597	0.01	100.00
5,001	6,000	0	318	0.00	100.00	0	218,597	0.00	100.00	0	218,597	0.00	100.00
6,001	7,000	0	318	0.00	100.00	0	218,597	0.00	100.00	0	218,597	0.00	100.00
7,001	8,000	0	318	0.00	100.00	0	218,597	0.00	100.00	0	218,597	0.00	100.00
8,001	9,000	0	318	0.00	100.00	0	218,597	0.00	100.00	0	218,597	0.00	100.00
9,001	10,000	0	318	0.00	100.00	0	218,597	0.00	100.00	0	218,597	0.00	100.00
10,001	& Above	0	318	0.00	100.00	0	218,597	0.00	100.00	0	218,597	0.00	100.00
Accounts with Credits		0	318			0	218,597						

Average kWh per Customer: 687.41 Average kWh per Customer including Credit Accounts: 687.41

Rate 109

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

05/13/20 :00:32 PM

Mohave Electric Cooperative, Inc.
Irrigation TOU (406)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block – Bills Each Block	Bills Ending In Block – Bills Accumulated	Bills Ending In Block – Percentage Each Block	Bills Ending In Block – Percentage Accumulated	Energy Ending In Block – kWh Each Block	Energy Ending In Block – kWh Accumulated	Energy Ending In Block – Percentage Each Block	Energy Ending In Block – Percentage Accumulated	Energy in Block – kWh Each Block	Energy in Block – kWh Accumulated	Energy in Block – Percentage Each Block	Energy in Block – Percentage Accumulated
0	0	58	58	30.21	30.21	0	0	0.00	0.00	0	0	0.00	0.00
1	10	0	58	0.00	30.21	0	0	0.00	0.00	1,340	1,340	0.05	0.05
11	20	0	58	0.00	30.21	0	0	0.00	0.00	1,340	2,680	0.05	0.11
21	30	0	58	0.00	30.21	0	0	0.00	0.00	1,340	4,020	0.05	0.16
31	40	2	60	1.04	31.25	80	80	0.00	0.00	1,340	5,360	0.05	0.22
41	50	0	60	0.00	31.25	0	80	0.00	0.00	1,320	6,680	0.05	0.27
51	60	0	60	0.00	31.25	0	80	0.00	0.00	1,320	8,000	0.05	0.32
61	70	1	61	0.52	31.77	64	144	0.00	0.01	1,314	9,314	0.05	0.37
71	80	1	62	0.52	32.29	80	224	0.00	0.01	1,310	10,624	0.05	0.43
81	90	0	62	0.00	32.29	0	224	0.00	0.01	1,300	11,924	0.05	0.48
91	100	0	62	0.00	32.29	0	224	0.00	0.01	1,300	13,224	0.05	0.53
101	200	10	72	5.21	37.50	1,647	1,871	0.07	0.08	12,647	25,871	0.51	1.04
201	300	2	74	1.04	38.54	444	2,315	0.02	0.09	11,844	37,715	0.48	1.52
301	400	4	78	2.08	40.63	1,346	3,661	0.05	0.15	11,546	49,261	0.46	1.98
401	500	1	79	0.52	41.15	418	4,079	0.02	0.16	11,318	60,579	0.46	2.44
501	600	3	82	1.56	42.71	1,704	5,783	0.07	0.23	11,204	71,783	0.45	2.89
601	700	0	82	0.00	42.71	0	5,783	0.00	0.23	11,000	82,783	0.44	3.33
701	800	1	83	0.52	43.23	720	6,503	0.03	0.26	10,920	93,703	0.44	3.77
801	900	0	83	0.00	43.23	0	6,503	0.00	0.26	10,900	104,603	0.44	4.21
901	1,000	0	83	0.00	43.23	0	6,503	0.00	0.26	10,900	115,503	0.44	4.65
1,001	2,000	9	92	4.69	47.92	13,533	20,036	0.54	0.81	104,533	220,036	4.21	8.85
2,001	3,000	6	98	3.13	51.04	16,432	36,468	0.66	1.47	98,432	318,468	3.96	12.81
3,001	4,000	5	103	2.60	53.65	17,120	53,588	0.69	2.16	91,120	409,588	3.67	16.48
4,001	5,000	10	113	5.21	58.85	46,646	100,234	1.88	4.03	85,646	495,234	3.45	19.93
5,001	6,000	6	119	3.13	61.98	32,080	132,314	1.29	5.32	75,080	570,314	3.02	22.95
6,001	7,000	4	123	2.08	64.06	25,767	158,081	1.04	6.36	70,767	641,081	2.85	25.79
7,001	8,000	6	129	3.13	67.19	45,440	203,521	1.83	8.19	66,440	707,521	2.67	28.47
8,001	9,000	2	131	1.04	68.23	17,348	220,869	0.70	8.89	62,348	769,869	2.51	30.97
9,001	10,000	4	135	2.08	70.31	37,221	258,090	1.50	10.38	58,221	828,090	2.34	33.32
10,001	& Above	57	192	29.69	100.00	2,227,375	2,485,465	89.62	100.00	1,657,375	2,485,465	66.68	100.00
Accounts with Credits		0	192			0	2,485,465						

Average kWh per Customer: 12,945.13 Average kWh per Customer including Credit Accounts: 12,945.13
Rate 406
Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Irrigation (407)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block: Bills Each Block	Bills Accumulated	Percentage Each Block	Percentage Accumulated	Energy Ending In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated	Energy In Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated
0	0	28	28	21.21	21.21	0	0	0.00	0.00	0	0	0.00	0.00
1	10	0	28	0.00	21.21	0	0	0.00	0.00	1,040	1,040	0.04	0.04
11	20	1	29	0.76	21.97	16	16	0.00	0.00	1,036	2,076	0.04	0.08
21	30	0	29	0.00	21.97	0	16	0.00	0.00	1,030	3,106	0.04	0.12
31	40	0	29	0.00	21.97	0	16	0.00	0.00	1,030	4,136	0.04	0.16
41	50	0	29	0.00	21.97	0	16	0.00	0.00	1,030	5,166	0.04	0.20
51	60	0	29	0.00	21.97	0	16	0.00	0.00	1,030	6,196	0.04	0.24
61	70	0	29	0.00	21.97	0	16	0.00	0.00	1,030	7,226	0.04	0.28
71	80	0	29	0.00	21.97	0	16	0.00	0.00	1,030	8,256	0.04	0.32
81	90	0	29	0.00	21.97	0	16	0.00	0.00	1,030	9,286	0.04	0.36
91	100	0	29	0.00	21.97	0	16	0.00	0.00	1,030	10,316	0.04	0.40
101	200	0	29	0.00	21.97	0	16	0.00	0.00	10,300	20,616	0.40	0.80
201	300	0	29	0.00	21.97	0	16	0.00	0.00	10,300	30,916	0.40	1.20
301	400	0	29	0.00	21.97	0	16	0.00	0.00	10,300	41,216	0.40	1.60
401	500	0	29	0.00	21.97	0	16	0.00	0.00	10,300	51,516	0.40	2.00
501	600	0	29	0.00	21.97	0	16	0.00	0.00	10,300	61,816	0.40	2.40
601	700	0	29	0.00	21.97	0	16	0.00	0.00	10,300	72,116	0.40	2.80
701	800	1	30	0.76	22.73	800	816	0.03	0.03	10,300	82,416	0.40	3.20
801	900	0	30	0.00	22.73	0	816	0.00	0.03	10,200	92,616	0.40	3.60
901	1,000	0	30	0.00	22.73	0	816	0.00	0.03	10,200	102,816	0.40	4.00
1,001	2,000	0	30	0.00	22.73	0	816	0.00	0.03	102,000	204,816	3.97	7.96
2,001	3,000	2	32	1.52	24.24	4,891	5,707	0.19	0.22	100,891	305,707	3.92	11.89
3,001	4,000	1	33	0.76	25.00	3,153	8,860	0.12	0.34	99,153	404,860	3.86	15.74
4,001	5,000	2	35	1.52	26.52	8,297	17,157	0.32	0.67	97,297	502,157	3.78	19.52
5,001	6,000	1	36	0.76	27.27	5,803	22,960	0.23	0.89	96,803	598,960	3.76	23.29
6,001	7,000	2	38	1.52	28.79	13,396	36,356	0.52	1.41	95,396	694,356	3.71	27.00
7,001	8,000	4	42	3.03	31.82	29,971	66,327	1.17	2.58	91,971	786,327	3.58	30.57
8,001	9,000	1	43	0.76	32.58	8,083	74,410	0.31	2.89	89,083	875,410	3.46	34.04
9,001	10,000	0	43	0.00	32.58	0	74,410	0.00	2.89	89,000	964,410	3.46	37.50
10,001	& Above	89	132	67.42	100.00	2,497,597	2,572,007	97.11	100.00	1,607,597	2,572,007	62.50	100.00
Accounts with Credits		0	132			0	2,572,007						

Average kWh per Customer: 19,484.90 Average kWh per Customer including Credit Accounts: 19,484.90

Rate 407

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

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Mohave Electric Cooperative, Inc.
Small Commercial Energy (504, 508)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block – Bills – Each Block	Bills Ending In Block – Bills – Accumulated	Bills Ending In Block – Percentage – Each Block	Bills Ending In Block – Percentage – Accumulated	Energy Ending In Block – kWh – Each Block	Energy Ending In Block – kWh – Accumulated	Energy Ending In Block – Percentage – Each Block	Energy Ending In Block – Percentage – Accumulated	Energy In Block – kWh – Each Block	Energy In Block – kWh – Accumulated	Energy In Block – Percentage – Each Block	Energy In Block – Percentage – Accumulated
0	0	2,243	2,243	5.82	5.82	0	0	0.00	0.00	0	0	0.00	0.00
1	10	567	2,810	1.47	7.29	2,516	2,516	0.01	0.01	360,066	360,066	0.86	0.86
11	20	432	3,242	1.12	8.41	6,792	9,308	0.02	0.02	355,702	715,768	0.85	1.70
21	30	448	3,690	1.16	9.57	11,480	20,788	0.03	0.05	351,270	1,067,038	0.84	2.54
31	40	489	4,179	1.27	10.84	17,410	38,198	0.04	0.09	346,600	1,413,638	0.82	3.36
41	50	462	4,641	1.20	12.03	20,939	59,137	0.05	0.14	341,699	1,755,337	0.81	4.18
51	60	470	5,111	1.22	13.25	26,047	85,184	0.06	0.20	337,087	2,092,424	0.80	4.98
61	70	376	5,487	0.97	14.23	24,529	109,713	0.06	0.26	332,749	2,425,173	0.79	5.77
71	80	399	5,886	1.03	15.26	30,141	139,854	0.07	0.33	329,001	2,754,174	0.78	6.55
81	90	349	6,235	0.90	16.17	29,862	169,716	0.07	0.40	325,242	3,079,416	0.77	7.33
91	100	352	6,587	0.91	17.08	33,529	203,245	0.08	0.48	321,629	3,401,045	0.77	8.09
101	200	3,164	9,751	8.20	25.28	469,500	672,745	1.12	1.60	3,034,500	6,435,545	7.22	15.31
201	300	2,739	12,490	7.10	32.39	687,151	1,359,896	1.63	3.24	2,746,851	9,182,396	6.53	21.84
301	400	2,682	15,172	6.95	39.34	938,402	2,298,298	2.23	5.47	2,473,102	11,655,498	5.88	27.73
401	500	2,447	17,619	6.35	45.69	1,101,256	3,399,554	2.62	8.09	2,217,056	13,872,554	5.27	33.00
501	600	1,939	19,558	5.03	50.71	1,062,951	4,462,505	2.53	10.62	1,994,151	15,866,705	4.74	37.75
601	700	1,583	21,141	4.10	54.82	1,029,040	5,491,545	2.45	13.06	1,821,640	17,688,345	4.33	42.08
701	800	1,383	22,524	3.59	58.41	1,036,827	6,528,372	2.47	15.53	1,672,827	19,361,172	3.98	46.06
801	900	1,234	23,758	3.20	61.61	1,048,723	7,577,095	2.49	18.03	1,542,223	20,903,395	3.67	49.73
901	1,000	1,182	24,940	3.06	64.67	1,122,699	8,699,794	2.67	20.70	1,421,399	22,324,794	3.38	53.11
1,001	2,000	7,175	32,115	18.60	83.27	10,190,595	18,890,389	24.24	44.94	9,465,595	31,790,389	22.52	75.63
2,001	3,000	3,091	35,206	8.02	91.29	7,571,715	26,462,104	18.01	62.95	4,748,715	36,539,104	11.30	86.93
3,001	4,000	1,539	36,745	3.99	95.28	5,316,725	31,778,829	12.65	75.60	2,519,725	39,058,829	5.99	92.92
4,001	5,000	864	37,609	2.24	97.52	3,842,327	35,621,156	9.14	84.74	1,342,327	40,401,156	3.19	96.11
5,001	6,000	435	38,044	1.13	98.65	2,370,053	37,991,209	5.64	90.38	716,053	41,117,209	1.70	97.82
6,001	7,000	229	38,273	0.59	99.24	1,483,378	39,474,587	3.53	93.91	401,378	41,518,587	0.95	98.77
7,001	8,000	125	38,398	0.32	99.57	930,970	40,405,557	2.21	96.12	222,970	41,741,557	0.53	99.30
8,001	9,000	62	38,460	0.16	99.73	528,522	40,934,079	1.26	97.38	137,522	41,879,079	0.33	99.63
9,001	10,000	47	38,507	0.12	99.85	446,538	41,380,617	1.06	98.44	81,538	41,960,617	0.19	99.82
10,001	& Above	58	38,565	0.15	100.00	653,896	42,034,513	1.56	100.00	73,896	42,034,513	0.18	100.00
Accounts with Credits		16	38,581			-5,096	42,029,417						

Average kWh per Customer: 1,089.97 Average kWh per Customer Including Credit Accounts: 1,089.38

Includes Rates 504, 508

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Small Commercial Demand (502, 503,509)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending in Block: Bills Each Block	Bills Accumulated	Percentage Each Block	Percentage Accumulated	Energy Ending in Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated	Energy in Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated
0	0	96	96	1.51	1.51	0	0	0.00	0.00	0	0	0.00	0.00
1	10	21	117	0.33	1.84	122	122	0.00	0.00	62,662	62,662	0.09	0.09
11	20	3	120	0.05	1.88	51	173	0.00	0.00	62,531	125,193	0.09	0.18
21	30	0	120	0.00	1.88	0	173	0.00	0.00	62,510	187,703	0.09	0.27
31	40	26	146	0.41	2.29	994	1,167	0.00	0.00	62,464	250,167	0.09	0.35
41	50	6	152	0.09	2.39	265	1,432	0.00	0.00	62,215	312,382	0.09	0.44
51	60	1	153	0.02	2.40	51	1,483	0.00	0.00	62,181	374,563	0.09	0.53
61	70	1	154	0.02	2.42	67	1,550	0.00	0.00	62,177	436,740	0.09	0.62
71	80	7	161	0.11	2.53	550	2,100	0.00	0.00	62,160	498,900	0.09	0.71
81	90	1	162	0.02	2.54	89	2,189	0.00	0.00	62,099	560,999	0.09	0.79
91	100	2	164	0.03	2.57	194	2,383	0.00	0.00	62,084	623,083	0.09	0.88
101	200	44	208	0.69	3.26	6,686	9,069	0.01	0.01	618,586	1,241,669	0.88	1.76
201	300	18	226	0.28	3.55	4,475	13,544	0.01	0.02	615,375	1,857,044	0.87	2.63
301	400	36	262	0.57	4.11	12,572	26,116	0.02	0.04	612,672	2,469,716	0.87	3.50
401	500	28	290	0.44	4.55	12,589	38,705	0.02	0.05	609,489	3,079,205	0.86	4.36
501	600	25	315	0.39	4.94	13,877	52,582	0.02	0.07	606,977	3,686,182	0.86	5.22
601	700	20	335	0.31	5.26	13,131	65,713	0.02	0.09	604,731	4,290,913	0.86	6.08
701	800	21	356	0.33	5.59	15,951	81,664	0.02	0.12	602,751	4,893,664	0.85	6.93
801	900	21	377	0.33	5.92	17,869	99,533	0.03	0.14	600,469	5,494,133	0.85	7.78
901	1,000	23	400	0.36	6.28	21,721	121,254	0.03	0.17	598,121	6,092,254	0.85	8.63
1,001	2,000	310	710	4.87	11.14	471,840	593,094	0.67	0.84	5,822,840	11,915,094	8.24	16.87
2,001	3,000	436	1,146	6.84	17.99	1,109,733	1,702,827	1.57	2.41	5,462,733	17,377,827	7.73	24.60
3,001	4,000	445	1,591	6.98	24.97	1,555,974	3,258,801	2.20	4.61	5,000,974	22,378,801	7.08	31.68
4,001	5,000	429	2,020	6.73	31.71	1,936,895	5,195,696	2.74	7.36	4,571,895	26,950,696	6.47	38.16
5,001	6,000	438	2,458	6.87	38.58	2,411,440	7,607,136	3.41	10.77	4,134,440	31,085,136	5.85	44.01
6,001	7,000	390	2,848	6.12	44.70	2,530,521	10,137,657	3.58	14.35	3,713,521	34,798,657	5.26	49.27
7,001	8,000	391	3,239	6.14	50.84	2,936,960	13,074,617	4.16	18.51	3,331,960	38,130,617	4.72	53.99
8,001	9,000	320	3,559	5.02	55.86	2,732,495	15,807,112	3.87	22.38	2,984,495	41,115,112	4.23	58.21
9,001	10,000	296	3,855	4.65	60.51	2,812,063	18,619,175	3.98	26.36	2,664,063	43,779,175	3.77	61.98
10,001	& Above	2,516	6,371	39.49	100.00	52,010,112	70,629,287	73.64	100.00	26,850,112	70,629,287	38.02	100.00
Accounts with Credits		0	6,371			0	70,629,287						

Average kWh per Customer: 11,086.06 Average kWh per Customer including Credit Accounts: 11,086.06

Includes Rates 502, 503, 509

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Small Commercial Time of Use (506)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending In Block: Bills Each Block	Bills Ending In Block: Bills Accum-ulated	Bills Ending In Block: Percentage Each Block	Bills Ending In Block: Percentage Accum-ulated	Energy Ending In Block: kWh Each Block	Energy Ending In Block: kWh Accum-ulated	Energy Ending In Block: Percentage Each Block	Energy Ending In Block: Percentage Accum-ulated	Energy In Block: kWh Each Block	Energy In Block: kWh Accum-ulated	Energy In Block: Percentage Each Block	Energy In Block: Percentage Accum-ulated
0	0	32	32	26.02	26.02	0	0	0.00	0.00	0	0	0.00	0.00
1	10	0	32	0.00	26.02	0	0	0.00	0.00	910	910	0.09	0.09
11	20	1	33	0.81	26.83	13	13	0.00	0.00	903	1,813	0.09	0.18
21	30	0	33	0.00	26.83	0	13	0.00	0.00	900	2,713	0.09	0.27
31	40	1	34	0.81	27.64	39	52	0.00	0.01	899	3,612	0.09	0.35
41	50	0	34	0.00	27.64	0	52	0.00	0.01	890	4,502	0.09	0.44
51	60	4	38	3.25	30.89	229	281	0.02	0.03	879	5,381	0.09	0.53
61	70	0	38	0.00	30.89	0	281	0.00	0.03	850	6,231	0.08	0.61
71	80	2	40	1.63	32.52	143	424	0.01	0.04	833	7,064	0.08	0.69
81	90	2	42	1.63	34.15	173	597	0.02	0.06	823	7,887	0.08	0.77
91	100	0	42	0.00	34.15	0	597	0.00	0.06	810	8,697	0.08	0.85
101	200	0	42	0.00	34.15	0	597	0.00	0.06	8,100	16,797	0.79	1.65
201	300	0	42	0.00	34.15	0	597	0.00	0.06	8,100	24,897	0.79	2.44
301	400	0	42	0.00	34.15	0	597	0.00	0.06	8,100	32,997	0.79	3.23
401	500	0	42	0.00	34.15	0	597	0.00	0.06	8,100	41,097	0.79	4.03
501	600	0	42	0.00	34.15	0	597	0.00	0.06	8,100	49,197	0.79	4.82
601	700	0	42	0.00	34.15	0	597	0.00	0.06	8,100	57,297	0.79	5.62
701	800	0	42	0.00	34.15	0	597	0.00	0.06	8,100	65,397	0.79	6.41
801	900	0	42	0.00	34.15	0	597	0.00	0.06	8,100	73,497	0.79	7.21
901	1,000	0	42	0.00	34.15	0	597	0.00	0.06	8,100	81,597	0.79	8.00
1,001	2,000	2	44	1.63	35.77	3,030	3,627	0.30	0.36	80,030	161,627	7.85	15.85
2,001	3,000	1	45	0.81	36.59	2,725	6,352	0.27	0.62	78,725	240,352	7.72	23.56
3,001	4,000	4	49	3.25	39.84	14,162	20,514	1.39	2.01	76,162	316,514	7.47	31.03
4,001	5,000	1	50	0.81	40.65	4,966	25,480	0.49	2.50	73,966	390,480	7.25	38.28
5,001	6,000	2	52	1.63	42.28	11,012	36,492	1.08	3.58	72,012	462,492	7.06	45.34
6,001	7,000	0	52	0.00	42.28	0	36,492	0.00	3.58	71,000	533,492	6.96	52.30
7,001	8,000	6	58	4.88	47.15	45,176	81,668	4.43	8.01	68,176	601,668	6.68	58.98
8,001	9,000	1	59	0.81	47.97	8,737	90,405	0.86	8.86	64,737	666,405	6.35	65.33
9,001	10,000	6	65	4.88	52.85	57,718	148,123	5.66	14.52	61,718	728,123	6.05	71.38
10,001	& Above	58	123	47.15	100.00	871,921	1,020,044	85.48	100.00	291,921	1,020,044	28.62	100.00
Accounts with Credits		0	123			0	1,020,044						

Average kWh per Customer: 8,293.04

Average kWh per Customer including Credit Accounts: 8,293.04

Rate 506

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

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Mohave Electric Cooperative, Inc.
Large Commercial (605,609)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending in Block: Bills Each Block	Bills Accumulated	Percentage Each Block	Percentage Accumulated	Energy Ending in Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated	Energy in Block: kWh Each Block	kWh Accumulated	Percentage Each Block	Percentage Accumulated
0	0	8	8	0.56	0.56	0	0	0.00	0.00	0	0	0.00	0.00
1	10	0	8	0.00	0.56	0	0	0.00	0.00	14,120	14,120	0.01	0.01
11	20	0	8	0.00	0.56	0	0	0.00	0.00	14,120	28,240	0.01	0.02
21	30	0	8	0.00	0.56	0	0	0.00	0.00	14,120	42,360	0.01	0.02
31	40	0	8	0.00	0.56	0	0	0.00	0.00	14,120	56,480	0.01	0.03
41	50	0	8	0.00	0.56	0	0	0.00	0.00	14,120	70,600	0.01	0.04
51	60	0	8	0.00	0.56	0	0	0.00	0.00	14,120	84,720	0.01	0.05
61	70	0	8	0.00	0.56	0	0	0.00	0.00	14,120	98,840	0.01	0.06
71	80	0	8	0.00	0.56	0	0	0.00	0.00	14,120	112,960	0.01	0.07
81	90	0	8	0.00	0.56	0	0	0.00	0.00	14,120	127,080	0.01	0.07
91	100	0	8	0.00	0.56	0	0	0.00	0.00	14,120	141,200	0.01	0.08
101	200	3	11	0.21	0.77	440	440	0.00	0.00	141,040	282,240	0.08	0.17
201	300	0	11	0.00	0.77	0	440	0.00	0.00	140,900	423,140	0.08	0.25
301	400	1	12	0.07	0.85	360	800	0.00	0.00	140,860	564,000	0.08	0.33
401	500	0	12	0.00	0.85	0	800	0.00	0.00	140,800	704,800	0.08	0.41
501	600	0	12	0.00	0.85	0	800	0.00	0.00	140,800	845,600	0.08	0.49
601	700	0	12	0.00	0.85	0	800	0.00	0.00	140,800	986,400	0.08	0.58
701	800	0	12	0.00	0.85	0	800	0.00	0.00	140,800	1,127,200	0.08	0.66
801	900	2	14	0.14	0.99	1,680	2,480	0.00	0.00	140,680	1,267,880	0.08	0.74
901	1,000	0	14	0.00	0.99	0	2,480	0.00	0.00	140,600	1,408,480	0.08	0.82
1,001	2,000	9	23	0.63	1.62	15,320	17,800	0.01	0.01	1,403,320	2,811,800	0.82	1.64
2,001	3,000	11	34	0.77	2.39	27,960	45,760	0.02	0.03	1,391,960	4,203,760	0.81	2.46
3,001	4,000	16	50	1.13	3.52	57,400	103,160	0.03	0.06	1,379,400	5,583,160	0.81	3.27
4,001	5,000	11	61	0.77	4.30	50,944	154,104	0.03	0.09	1,365,944	6,949,104	0.80	4.06
5,001	6,000	8	69	0.56	4.86	45,080	199,184	0.03	0.12	1,356,080	8,305,184	0.79	4.86
6,001	7,000	7	76	0.49	5.35	47,480	246,664	0.03	0.14	1,349,480	9,654,664	0.79	5.65
7,001	8,000	13	89	0.92	6.27	98,200	344,864	0.06	0.20	1,338,200	10,992,864	0.78	6.43
8,001	9,000	9	98	0.63	6.90	77,800	422,664	0.05	0.25	1,327,800	12,320,664	0.78	7.21
9,001	10,000	5	103	0.35	7.25	46,720	469,384	0.03	0.27	1,318,720	13,639,384	0.77	7.98
10,001	& Above	1,317	1,420	92.75	100.00	170,497,554	170,966,938	99.73	100.00	157,327,554	170,966,938	92.02	100.00
Accounts with Credits		0	1,420			0	170,966,938						

Average kWh per Customer: 120,399.25 Average kWh per Customer including Credit Accounts: 120,399.25

Includes Rates 605, 609, 611, 612, 615

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Mohave Electric Cooperative, Inc.
Large Commercial TOU (606)

Total

kWh Lower Bound	Block Upper Bound	Bills Ending in Block – Bills Each Block	Accumulated	Percentage Each Block	Percentage Accumulated	Energy Ending in Block – kWh Each Block	Accumulated	Percentage Each Block	Percentage Accumulated	Energy in Block – kWh Each Block	Accumulated	Percentage Each Block	Percentage Accumulated
0	0	14	14	32.56	32.56	0	0	0.00	0.00	0	0	0.00	0.00
1	10	0	14	0.00	32.56	0	0	0.00	0.00	290	290	0.05	0.05
11	20	0	14	0.00	32.56	0	0	0.00	0.00	290	580	0.05	0.10
21	30	0	14	0.00	32.56	0	0	0.00	0.00	290	870	0.05	0.15
31	40	0	14	0.00	32.56	0	0	0.00	0.00	290	1,160	0.05	0.21
41	50	0	14	0.00	32.56	0	0	0.00	0.00	290	1,450	0.05	0.26
51	60	0	14	0.00	32.56	0	0	0.00	0.00	290	1,740	0.05	0.31
61	70	0	14	0.00	32.56	0	0	0.00	0.00	290	2,030	0.05	0.36
71	80	0	14	0.00	32.56	0	0	0.00	0.00	290	2,320	0.05	0.41
81	90	0	14	0.00	32.56	0	0	0.00	0.00	290	2,610	0.05	0.46
91	100	0	14	0.00	32.56	0	0	0.00	0.00	290	2,900	0.05	0.51
101	200	0	14	0.00	32.56	0	0	0.00	0.00	2,900	5,800	0.51	1.03
201	300	0	14	0.00	32.56	0	0	0.00	0.00	2,900	8,700	0.51	1.54
301	400	0	14	0.00	32.56	0	0	0.00	0.00	2,900	11,600	0.51	2.05
401	500	0	14	0.00	32.56	0	0	0.00	0.00	2,900	14,500	0.51	2.57
501	600	0	14	0.00	32.56	0	0	0.00	0.00	2,900	17,400	0.51	3.08
601	700	0	14	0.00	32.56	0	0	0.00	0.00	2,900	20,300	0.51	3.59
701	800	0	14	0.00	32.56	0	0	0.00	0.00	2,900	23,200	0.51	4.11
801	900	0	14	0.00	32.56	0	0	0.00	0.00	2,900	26,100	0.51	4.62
901	1,000	0	14	0.00	32.56	0	0	0.00	0.00	2,900	29,000	0.51	5.13
1,001	2,000	1	15	2.33	34.88	1,640	1,640	0.29	0.29	28,640	57,640	5.07	10.20
2,001	3,000	0	15	0.00	34.88	0	1,640	0.00	0.29	28,000	85,640	4.96	15.16
3,001	4,000	0	15	0.00	34.88	0	1,640	0.00	0.29	28,000	113,640	4.96	20.12
4,001	5,000	1	16	2.33	37.21	4,280	5,920	0.76	1.05	27,280	140,920	4.83	24.95
5,001	6,000	1	17	2.33	39.53	5,280	11,200	0.93	1.98	26,280	167,200	4.65	29.60
6,001	7,000	0	17	0.00	39.53	0	11,200	0.00	1.98	26,000	193,200	4.60	34.20
7,001	8,000	0	17	0.00	39.53	0	11,200	0.00	1.98	26,000	219,200	4.60	38.80
8,001	9,000	0	17	0.00	39.53	0	11,200	0.00	1.98	26,000	245,200	4.60	43.41
9,001	10,000	0	17	0.00	39.53	0	11,200	0.00	1.98	26,000	271,200	4.60	48.01
10,001	& Above	26	43	60.47	100.00	553,680	564,880	98.02	100.00	293,680	564,880	51.99	100.00
Accounts with Credits		0	43			0	564,880						

Average kWh per Customer: 13,136.74 Average kWh per Customer including Credit Accounts: 13,136.74

Rate 606

Includes Months Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec

Supplemental Section L

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SUPPLEMENTAL SCHEDULE M

Supplemental Section M

2010 Audit

2010 Form 7

Supplemental Section M

2010 Audit

MOHAVE ELECTRIC COOPERATIVE, INC.

CONTENTS

MOHAVE ELECTRIC COOPERATIVE, INC.

OFFICERS, BOARD OF DIRECTORS AND CEO

Name	Office	Address
Lyn R. Opalka	President	Bullhead City, AZ
John B. Neissen	Vice-President	Wikieup, AZ
Chester Moreland	Secretary	Bullhead City, AZ
Carlos A. Tejeda	Treasurer	Bullhead City, AZ
Jack Christy	Director	Bullhead City, AZ
Gordon Ennes	Director	Bullhead City, AZ
Joe Anderson	Director	Bullhead City, AZ
Michael Bartelt	Director	Bullhead City, AZ
John Elkins	Director	Bullhead City, AZ
J. Tyler Carlson	CEO	Bullhead City, AZ

INDEPENDENT AUDITORS' REPORT

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

We have audited the accompanying balance sheet of Mohave Electric Cooperative, Inc. as of December 31, 2010, and the related statements of revenue and patronage capital and cash flows for the year then ended. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of Mohave Electric Cooperative, Inc. for the year ended December 31, 2009 were audited by other auditors, whose report dated June 20, 2010 expressed an unqualified opinion on those statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the Government Auditing Standards issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion the financial statements referred to above present fairly, in all material respects, the financial position of Mohave Electric Cooperative, Inc. as of December 31, 2010, and the results of its operations and cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, we have also issued a report dated May 17, 2011, on our consideration of Mohave Electric Cooperative, Inc.'s internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts and grants. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the result of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be considered in assessing the results of our audit.

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The accompanying schedule of federal awards is presented for purposes of additional analysis as required by U.S. Office of Management and Budget Circular A-133, Audits of States, Local Governments, and Non-Profit Organizations, and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated, in all material respects, in relation to the basic financial statements taken as whole.

Dreyer & Kelso, P.C., P.A.

May 17, 2011

MOHAVE ELECTRIC COOPERATIVE, INC.

BALANCE SHEETS

December 31, 2010 and 2009

ASSETS

	2010	2009
UTILITY PLANT		
Electric plant in service	$ 88,890,934	$ 88,368,544
Construction work in progress	3,021,375	428,827
	91,912,309	88,797,371
Less: accumulated depreciation	(35,708,315)	(33,642,088)
Total Utility Plant	56,203,994	55,155,283
INVESTMENTS		
Subordinated certificates	2,802,850	2,810,718
Investments in associated organizations	30,024,396	26,468,823
Non-utility property	150,000	150,000
Other investments	2,751,898	1,754,400
Total Investments	35,729,144	31,183,941
CURRENT ASSETS		
Cash and cash equivalents	20,370,432	19,924,396
Note receivable - current portion	127,374	111,823
Accounts receivable (less allowance for doubtful accounts of $197,000 in 2010 and $212,000 in 2009)	5,405,118	5,360,120
Materials and supplies	2,115,226	2,132,276
Other current assets	607,515	505,483
Total Current Assets	28,625,665	28,034,098
DEFERRED CHARGES	14,479,221	16,042,019
TOTAL ASSETS	$ 135,038,024	$ 130,415,341

The accompanying notes to the financial statements are an integral part of this statement

MEMBERS' EQUITY AND LIABILITIES

	2010	2009
MEMBERS' EQUITY		
Patronage capital	$ 67,565,118	$ 65,446,465
Other equities	2,237,413	2,180,753
Total Members' Equity	69,802,531	67,627,218
LONG-TERM DEBT		
Mortgage notes	39,140,805	40,765,556
Less: current maturities	(1,695,000)	(1,623,622)
Total Long-Term Debt	37,445,805	39,141,934
CURRENT LIABILITIES		
Current maturities of long-term debt	1,695,000	1,623,622
Accounts payable	5,659,565	4,443,446
Accrued interest payable	72,983	55,321
Accrued taxes	838,113	878,792
Other current liabilities	3,351,607	2,878,421
Total Current Liabilities	11,617,268	9,879,602
DEFERRED CREDITS	16,172,420	13,766,587
TOTAL MEMBERS' EQUITY AND LIABILITIES	$ 135,038,024	$ 130,415,341

MOHAVE ELECTRIC COOPERATIVE, INC.

STATEMENTS OF REVENUE AND PATRONAGE CAPITAL

FOR THE YEARS ENDED DECEMBER 31

	2010	2009
OPERATING REVENUE		
Sale of electricity	$ 69,768,736	$ 71,654,111
Other operating revenue	749,068	720,503
Total Operating Revenue	70,517,804	72,374,614
OPERATING EXPENSE		
Cost of power	56,294,063	58,273,523
Transmission expense	169,400	374,367
Distribution - operations	2,773,701	2,407,216
Distribution - maintenance	1,194,658	1,397,297
Consumer accounts	2,227,247	2,332,076
Customer service and information	292,478	270,531
Administrative and general	4,756,456	4,301,230
Depreciation and amortization	2,239,667	2,176,550
Interest on long-term debt	2,161,308	2,208,733
Interest expense - other	142,396	118,932
Total Operating Expense	72,251,374	73,860,455
NET OPERATING MARGIN (LOSS)	(1,733,570)	(1,485,841)
NON-OPERATING MARGIN		
Interest income	410,049	499,868
Other non-operating income	61,039	107,228
Total Non-Operating Margin	**471,088**	**607,096**
CAPITAL CREDITS	**3,617,656**	**6,498,576**
NET MARGINS FOR PERIOD	**2,355,174**	**5,619,831**
PATRONAGE CAPITAL - BEGINNING OF YEAR	65,446,465	60,267,905
	67,801,639	65,887,736
Retirement of capital credits	(236,521)	(441,271)
PATRONAGE CAPITAL - END OF YEAR	**$ 67,565,118**	**$ 65,446,465**

The accompanying notes to the financial statements
are an integral part of this statement

MOHAVE ELECTRIC COOPERATIVE, INC.

STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31

	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers	$ 72,939,678	$ 72,373,870
Interest and dividends received	410,049	499,868
Cash paid to suppliers and employees	(64,598,611)	(63,134,063)
Interest paid	(2,286,042)	(2,324,197)
Net Cash Provided (Used) By Operating Activities	6,465,074	7,415,478
CASH FLOWS FROM INVESTING ACTIVITIES:		
Investment in plant	(3,288,378)	(888,851)
Materials and supplies	17,050	347,218
Patronage capital recovery	69,951	31,303
Other investing activities	(1,013,049)	(1,924,871)
Net Cash Provided (Used) By Investing Activities	**(4,214,426)**	**(2,435,201)**
CASH FLOWS FROM FINANCING ACTIVITIES:		
Loan funds received	-0-	1,106,000
Retirement of long-term debt	(1,624,751)	(1,555,703)
Retirement of capital credits	(236,521)	(441,271)
Other financing activities	56,660	110,485
Net Cash Provided (Used) By Financing Activities	**(1,804,612)**	**(780,489)**
NET INCREASE IN CASH AND CASH EQUIVALENTS	**446,036**	**4,199,788**
Cash and cash equivalents - Beginning of year	19,924,396	15,724,608
CASH AND CASH EQUIVALENTS - END OF YEAR	**$ 20,370,432**	**$ 19,924,396**

The accompanying notes to financial statements are an integral part of this statement

MOHAVE ELECTRIC COOPERATIVE, INC.

STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31

	2010	2009
RECONCILIATION OF NET MARGIN TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Net margin	$ 2,355,174	$ 5,619,831
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation and amortization	2,239,667	2,176,550
Patronage capital credits from suppliers	(3,617,656)	(6,498,575)
(Increase) decrease in accounts receivable	(44,998)	1,655,598
(Increase) decrease in deferred debits	1,562,798	(273,706)
(Increase) decrease in other assets	(102,032)	140,403
Increase (decrease) in accounts payable	1,216,119	4,513,802
Increase (decrease) in interest payable	17,662	3,468
Increase (decrease) in accrued taxes	(40,679)	105,631
Increase (decrease) in other liabilities	473,186	468,019
Increase (decrease) in deferred credits	2,405,833	(495,543)
Net Cash Provided (Used) By Operating Activities	**$ 6,465,074**	**$ 7,415,478**

The accompanying notes to financial statements are an integral part of this statement

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Cooperative is a Rural Electric Cooperative whose principal business is the distribution of electrical power to residences and businesses located in three counties in northwest Arizona. As a regulated enterprise with a member-elected board of directors, the Cooperative accounts for such regulation under professional accounting standards ASC 980, Regulated Industries. The accounting policies followed by the Cooperative are in conformity with generally accepted accounting principles as they apply to a regulated electric utility. The rates are regulated by the Arizona Corporation Commission (ACC) and are designed to recover the cost of providing electric distribution to the members of the Cooperative.

The Cooperative employs the Uniform System of Accounts prescribed by the Rural Utilities Service (RUS). As a result, the application of generally accepted accounting principles by the Cooperative differs in certain respects from such application by non-regulated enterprises. These differences primarily concern the timing of the recognition of certain revenue and expense items.

Depreciation is recorded on the composite basis for transmission and distribution plant, and the unit basis (straight-line basis) for general plant, and is charged to capital and operating accounts at rates adopted by the Board of Directors in conformity with guidelines provided by RUS and the ACC. Depreciation provisions are computed on additions beginning the month after they are placed in service. When units of property are retired, their average cost (specific unit cost for substantially all of the general plant) is removed from utility plant and the cost, less net salvage, is removed from allowances for depreciation. Expenditures for normal repairs and maintenance are charged to operations as incurred.

Continuing property records are maintained on a current basis. These provide the average installed cost of the plant in service.

The Cooperative has determined that it does not have any long-lived assets for which it has a contractual or legal obligation to remove in the future.

Investments in associated organizations are carried at face value of equity certificates. Other amounts included in investments are generally carried at cost or fair value depending upon the classification of the securities.

The Cooperative carries its accounts receivable at cost less an allowance for doubtful accounts. On a periodic basis, the Cooperative evaluates its electric accounts receivable and establishes an allowance for doubtful accounts, based on past history of bad debt write-offs, collections, and current credit conditions. Electric accounts receivable are generally considered past due if the Cooperative

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

has not received payment by the due date of the bill and are generally turned over for collection if they remain unpaid for 90 days. It is the Cooperative's policy that accounts are written off if they remain uncollected, and collection efforts have been exhausted. Payments received on accounts after they are written off are considered a recovery of the bad debt. As of December 31, 2010 and 2009, the Cooperative had approximately $49,000 and $163,000, respectively, in electric accounts receivable that were over 90 days old and the balance in the allowance for doubtful accounts approximated $197,000 and $212,000, respectively.

Materials and supplies are stated at average cost.

For purposes of the Statement of Cash Flows, the Cooperative considers all short-term deposits and highly liquid investments with an original maturity date of three months or less to be cash and cash equivalents.

The Cooperative follows industry practice of recording revenue concurrently with its billings to customers, net of taxes collected for taxing authorities, and recording cost of power upon receipt of their billing from the supplier. Revenue is not accrued for power delivered and not billed as of the end of each month. As of December 31, 2010 and 2009, this unbilled revenue is estimated at approximately $2,693,600 and $3,313,000, respectively.

In conformity with its bylaws, the Cooperative conducts its operations on a cooperative nonprofit basis. Annual revenue, in excess of the cost of providing service, is allocated in the form of capital credits to the customers' capital accounts on the basis of patronage.

The Cooperative has a letter of exemption from Federal income tax, issued by the Internal Revenue Service, and files IRS Form 990 annually.

Financial Accounting Standards Board Interpretation No. 48 (FSP FIN 48), Accounting for Uncertainty in Income Taxes, which is codified at FASB ASC 740, Income Taxes, was issued in 2006. Hence, there have been three amendments to defer the effective date of implementation, including the most recent, FSP FIN 48-3 (ASC 740), which deferred the implementation date to fiscal years beginning on or after December 15, 2008. The Cooperative adopted FSP FIN 48 (ASC 740) effective January 1, 2009. An evaluation of whether or not it has any uncertain tax positions is determined on an annual basis by the Cooperative. While the Cooperative believes it has adequately provided for all tax positions, amounts asserted by taxing authorities could be different than the positions taken by the Cooperative. The Cooperative recognizes any interest and penalties assessed by taxing authorities in income tax expense.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

CERTAIN SIGNIFICANT RISKS AND UNCERTAINTIES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect certain reported amounts and disclosures. Accordingly, actual results could differ from those estimates.

Two members accounted for 8% of the electric revenues reported for both the years ended December 31, 2010 and 2009, and the loss of any one could have an adverse effect on the Cooperative. However, management does not expect that the business relationship with either of these members will be lost.

The Cooperative's collective bargaining agreement expires in the near-term. Management does not expect any work stoppage.

Concentrations of credit risk arises from the Cooperative's granting of credit to its member customers, uninsured funds deposited in federally insured financial institutions which may be in excess of the insurance limits at various times during the year, and other uninsured cash funds of $18,100,000 at December 31, 2009.

ASSETS PLEDGED

Substantially all assets are pledged as security for long-term debt to RUS, and the Federal Financing Bank (FFB), and concurrent mortgage notes to the National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank.

UTILITY PLANT

A summary of the utility plant and accumulated depreciation follows:

	December 31	
	2010	2009
Intangible plant	$ 579	$ 579
Transmission plant	11,200,152	11,182,870
Distribution plant	68,612,970	68,073,168
General plant	9,077,233	9,111,927
Total Electric Plant	**88,890,934**	**88,368,544**
Construction work in progress	3,021,375	428,827
	91,912,309	**88,797,371**

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

UTILITY PLANT (Continued)

	December 31	
	2010	2009
Accumulated depreciation:		
Transmission plant	$ 3,246,282	$ 2,964,283
Distribution plant	26,372,638	24,648,546
General plant	6,097,478	6,032,255
	35,716,398	**33,645,084**
Retirement work in progress	(8,083)	(2,996)
	35,708,315	**33,642,088**
Net Utility Plant	**$ 56,203,994**	**$ 55,155,283**

Transmission plant is depreciated, under the straight-line composite basis, at the annual rate of 2.75%.

Distribution plant is depreciated, under the straight-line composite basis, at the annual rate of 3.00%.

General plant is depreciated over the estimated useful life of the assets, under the straight-line composite basis, at various rates ranging from 2.00% to 20.00%.

During the year ended December 31, 2009, the Cooperative changed its estimate on the economic life of the electric plant by updating its depreciation rates based on a depreciation study conducted in 2009. The Cooperative applied the change in estimate prospectively in 2009 in accordance with ASC 250-10-50-4. The result was an increase in depreciation expense of approximately $300,000 for the year ended December 31, 2009.

SUBORDINATED CERTIFICATES

	December 31	
	2010	2009
Capital term certificates	$ 562,410	$ 562,410
Loan term certificates	117,500	117,500
Zero term certificates	122,940	130,808
Member capital securities	2,000,000	2,000,000
Total	**$2,802,850**	**$2,810,718**

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

SUBORDINATED CERTIFICATES (Continued)

The capital term certificates yield 5.00%, the loan term certificates yield 3.00%, and the zero term certificates have no yield. All of the certificates have various maturity dates through the year 2080.

The member capital securities have an interest rate of 7.50%, with a first call date of August 26, 2014, and a maturity date of December 23, 2044.

INVESTMENTS IN ASSOCIATED ORGANIZATIONS

This category consists mainly of patronage capital due from organizations of which the Cooperative is a member.

	December 31	
	2010	2009
Patronage capital - CFC	$ 345,457	$ 322,050
Patronage capital - Arizona Electric Power Cooperative, Inc.	26,350,787	22,850,473
Patronage capital - Southwest Transmission Cooperative, Inc.	2,347,466	2,337,712
Patronage capital - NRTC	659,608	671,156
Patronage capital - CoBank	130,073	124,111
Patronage capital-Federated Rural Insurance Exchange	109,280	89,302
Other investments in associated organizations	81,725	74,019
Total	$30,024,396	$26,468,823

OTHER INVESTMENTS

	December 31	
	2010	2009
Note receivable - sale of DirecTV rights	$ 1,664,400	$ 1,776,223
Notes receivable-renewable energy projects	375,000	-0-
Note receivable - employee	80,000	90,000
Marketable securities	759,872	-0-
	2,879,272	1,866,223
Less: current portion	(127,374)	(111,823)
Total	$ 2,751,898	$ 1,754,400

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

OTHER INVESTMENTS (Continued)

The gain on the sale of DirecTV rights is being deferred and recognized over the installment period noted below. Principal payments of $111,823 and $106,534 were received for the year ended December 31, 2010 and 2009, respectively. The note is carried at cost, is current at both December 31, 2010 and 2009, is unsecured, and management believes it is collectible. It matures in 2021.

The other notes receivable are carried at cost, are current at both December 31, 2010 and 2009, and are unsecured. Management believes they will be collected. The note receivable-employee is repaid through payroll deduction.

The Cooperative determines the appropriate classification of its investment securities (debt and equity securities) at the time of purchase and reevaluates such determinations at each balance sheet date. Investments are classified as held-to-maturity when the Cooperative has the positive intent and ability to hold the securities to maturity. For those not classified as held-to-maturity, they are classified as available for sale since the Cooperative does not intend to sell them in the near-term. The investments classified as held-to-maturity are stated at cost and those classified as available for sale are stated at fair value, as determined by quoted market prices.

As of December 31, 2010, marketable securities consisted of the following:

	Cost	Fair Value	Unrealized Gains (Losses)
Held-to-maturity securities	$128,558	$128,380	$(178)
Available for sale securities	635,000	631,492	(3,508)
Total	$763,558	$759,872	$(3,686)

The Cooperative did not sell any of its marketable securities during the year ended December 31, 2010, and recorded the unrealized loss in the financial statements. All of the securities are classified as non-current.

NON-UTILITY PROPERTY

	December 31 2010	2009
Real estate	$150,000	$150,000

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

OTHER CURRENT ASSETS

	December 31	
	2010	2009
Prepaid insurance	$112,143	$122,476
Interest receivable	45,766	48,930
Prepaid dues	184,898	34,029
Prepaid purchased power	178,394	225,391
Prepaid right of way rent	56,622	35,686
Undistributed warehouse expense	305	-0-
Other prepaid expenses	29,387	38,971
Total	$607,515	$505,483

DEFERRED CHARGES

	December 31	
	2010	2009
Past service pension cost	$ 607,941	$ 655,822
Construction advances	13,705,566	15,294,869
Preliminary survey and investigation	47,082	86,910
Work plans	127,410	13,183
Undistributed transportation expense	575	-0-
Other deferred charges	(9,353)	(8,765)
Total	$ 14,479,221	$ 16,042,019

Past service pension cost is amortized on the straight-line basis over future periods as allowed for under the Statement of Financial Accounting Standards No. 71 (SFAS 71), which is codified at FASB ASC 980, Regulated Enterprises. Amortization amounted to $47,881 for both the years ended December 31, 2010 and 2009.

The construction advances made on transmission projects will be recovered over future periods through credits on purchased power from the Cooperative's power suppliers as per the contractual agreements.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

MEMBERS' EQUITY

	Patronage Capital Credits	Patronage Capital Unallocated	Other Equities	Total
Balance December 31, 2008	$ 52,116,114	$ 8,151,791	$ 2,070,268	$ 62,338,173
Net margin, year 2009	-0-	5,619,831	-0-	5,619,831
2008 allocation	8,151,796	(8,151,796)	-0-	-0-
Capital credits retired	(441,271)	-0-	111,159	(330,112)
Other changes	-0-	-0-	(674)	(674)
Balance December 31, 2009	59,826,639	5,619,826	2,180,753	67,627,218
Net margin, year 2010	-0-	2,355,174	-0-	2,355,174
Capital credits retired	(236,521)	-0-	78,750	(157,771)
Other changes	(387,675)	387,675	(22,090)	(22,090)
Balance December 31, 2010	$ 59,202,443	$ 8,362,675	$ 2,237,413	$ 69,802,531

Under the provisions of the RUS mortgage agreement, until the equities and margins equal or exceed thirty percent of the total assets of the Cooperative, the retirement of capital credits is generally limited to twenty-five percent of the patronage capital or margins from the prior calendar year. The CFC and CoBank mortgage agreement provisions differ slightly. This limitation does not usually apply to capital credit retirements made exclusively to estates.

The total equities of the Cooperative are approximately 52% of the total assets as of both December 31, 2010 and 2009. Other equities consist of memberships, donated capital and retired capital credits gain.

LONG-TERM DEBT

Long-term debt consists of mortgage notes payable to RUS and CFC with various maturities through 2039.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

LONG-TERM DEBT (Continued)

The following is a summary of these notes:

	December 31 2010	December 31 2009
RUS mortgage notes	$ 14,816,618	$ 15,770,992
CFC mortgage notes	5,573,455	5,932,082
FFB mortgage notes	17,093,736	17,373,863
CoBank mortgage notes	1,656,996	1,688,619
	39,140,805	40,765,556
Less: current maturities	(1,695,000)	(1,623,622)
Total Long-Term Debt	$ 37,445,805	$ 39,141,934

The RUS notes have fixed interest rates that ranged between 2.00% and 5.25% as of both December 31, 2010 and 2009.

The CFC notes have fixed interest rates that ranged between 5.75% and 8.75% as of both December 31, 2010 and 2009.

The FFB notes have fixed interest rates that ranged between 4.006% and 5.053% as of both December 31, 2010 and 2009.

The CoBank note has a fixed interest rate of 7.25% as of both December 31, 2010 and 2009.

Based on current obligations, principal payments toward the above long-term debt for the next five years will require approximately:

2011	$1,695,000
2012	$1,735,000
2013	$1,810,000
2014	$1,845,000
2015	$1,925,000

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

OTHER CURRENT LIABILITIES

	December 31	
	2010	2009
Customers' deposits	$2,732,714	$2,131,282
Patronage capital payable	34,062	54,372
Accrued payroll	265,690	337,680
Accrued employees vacation	287,091	296,926
Other current liabilities	32,050	58,161
Total	$3,351,607	$2,878,421

SHORT-TERM LINE OF CREDIT

The Cooperative has a $5,800,000 line of credit agreement with a variable interest rate, established with CFC. It expires March 9, 2011 and was renewed subsequent to December 31, 2010. No funds had been drawn as of December 31, 2010 and 2009. Certain pre-conditions may be required of the Cooperative prior to draw down of these funds, such as repayment of the entire balance once a year.

DEFERRED CREDITS

	December 31	
	2010	2009
Customers' prepayments	$ 805,439	$ 737,470
Customers' advances for construction	3,868,870	5,024,136
Deferred gain - sale of DirecTV rights	1,214,052	1,324,421
Deferred revenue assessments	974,861	1,293,298
Accumulated over-recovery of power cost	9,145,832	5,199,806
Other deferred credits	163,366	187,456
Total	$16,172,420	$13,766,587

The Cooperative sold its exclusive DirecTV rights back to an affiliated organization, Western Competitive Solutions, Inc. (Western), an Arizona corporation, in a previous year. The Cooperative is deferring the gain from the sale over the life of the corresponding note receivable established by SFAS No. 71 (ASC 980) on a straight-line basis. The amount of gain recognized in 2010 and 2009 was $110,369 for each year, and is included in the caption "Other non-operating revenue" in the Statement of Revenue and Patronage Capital.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

DEFERRED CREDITS (Continued)

The Cooperative's tariffs for electric service, as approved by the ACC, include a power cost recovery factor under which any differences between the revenue generated from the power cost included in base rates and actual power cost are deferred and are either charged or credited to customers' monthly billings in future periods. As of both December 31, 2010 and 2009, the Cooperative had accumulated net over-recovery of $9,145,832 and $5,199,806, respectively.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair value amounts have been determined by the Corporation using available market information and other appropriate valuation methods.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments, for which it is practicable to estimate the value set forth in Statement of Accounting Standards No. 107 (SFAS 107), which is codified at FASB ASC 820, Fair Value Measurements and Disclosures.

Cash and cash equivalents - The carrying amount approximates the fair value.

Fixed-rate debt - The fair value is determined based on the discounted cash flows using current interest rates available to the Corporation for similar debt.

	December 31, 2010	
	Carrying Amount	Estimated Fair Amount
Assets:		
Cash and cash equivalents	$20,370,432	$20,370,432
Investments	$ 2,751,898	(1)
Subordinated certificates	$ 2,802,850	(1)
Other associations	$30,024,396	(1)
Liabilities:		
Long-term debt	$39,140,805	$42,873,949

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

	December 31, 2009	
	Carrying Amount	Estimated Fair Amount
Assets:		
Cash and cash equivalents	$19,924,396	$19,924,396
Investments	$ 1,754,400	(1)
Subordinated certificates	$ 2,810,718	(1)
Other associations	$26,468,823	(1)
Liabilities:		
Long-term debt	$40,765,556	$44,362,244

(1) Management was not able to estimate the fair value of these instruments, since they are not marketable.

CASH FLOWS INFORMATION

	December 31	
	2010	2009
Cash and cash equivalents:		
General funds	$ 1,651,369	$ 1,824,396
Uninsured cash investments	18,719,063	18,100,000
Total	**$20,370,432**	**$19,924,396**

PENSION PLAN

Substantially all employees of the Cooperative participate in the NRECA Retirement and Security Program, a defined benefit pension plan qualified under the Internal Revenue Code. The Cooperative makes annual contributions to the Program equal to amounts accrued for pension expense. In this multi-employer plan the accumulated benefits and plan assets are not determined or allocated separately by individual employer. Pension expense incurred during the years ending December 31, 2010 and 2009 consisted of the following:

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

PENSION PLAN (Continued)

	December 31	
	2010	2009
Past service pension cost	$ 47,881	$ 47,881
Current payments to plan	841,089	572,811
Total	$888,970	$620,692

Employees of the Cooperative can participate in the National Rural Electric Cooperative Association (NRECA) SelectRE 401(k) plan, provided they meet plan specifications. The Cooperative will contribute up to 5% of matching contributions. The Cooperative's contribution for the years ended December 31, 2010 and 2009 was $182,757 and $173,088 respectively.

Management expects benefit payments for both plans to approximate the following for the next ten years:

2011	$1,092,000
2012	$1,162,000
2013	$1,233,000
2014	$1,306,000
2015	$1,380,000
2016 to 2020	$8,061,000

The Cooperative has learned from NRECA that the defined benefit plan mentioned above is under-funded, and additional increases in the contributions, assuming no changes are made to the plan, may be required. This may include an increase to future contributions to the plan and possibly a past service pension cost assessment. The amount of these potential increases is unknown, but may be significant to future operating results and financial statements taken as a whole.

DEFERRED COMPENSATION

The Cooperative has a non-qualified deferred compensation plan for a former officer of the Cooperative. The plan benefits are payable to the Cooperative, for the benefit of the former employee, and the agreement provides for payment of benefits upon the occurrence of certain events, as specified in the agreement. The plan assets and liability are recorded in the financial statements.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

PARTICIPATION IN POWER POOL

The Cooperative has entered into an agreement with Aggregated Energy Services (AES), which functions as a resource aggregator in coordination with the Western Area Power Administration (WAPA). The Cooperative is a participant in AES and entered into an Aggregation Agreement with AES to more efficiently use its resources to meet demand. WAPA acts, under the AES agreement, as the scheduling and dispatch agent and manages the electric resources available to the AES Group.

Subsequent to year-end each year, the two parties will agree on a settlement (true-up) for the previous year's transactions. This settlement will then be recognized as a receivable or payable to AES in the financial statements. The true-up settlement for both the years ended December 31, 2010 and 2009 was not significant to the financial statements taken as a whole; however, it was recognized and recorded in cost of power in the Statement of Revenue and Patronage Capital each year.

RELATED PARTY TRANSACTIONS

The Cooperative is a member of Arizona Electric Power Cooperative, Inc. (AEPCO) which is an electric generation and transmission cooperative. The Cooperative obtains a portion of its purchased power from AEPCO, as noted below, which amounted to $45,494,600 and $46,559,580 for the years ended December 31, 2010 and 2009, respectively. The Cooperative is also a member of Southwest Transmission Cooperative, Inc. (TRANSCO), which is an electric transmission cooperative. The Cooperative obtains a portion of its purchased power from TRANSCO, as noted below, which amounted to $6,766,961 and $6,923,930 for the years ended December 31, 2010 and 2009, respectively. Although there are a limited number of electrical power suppliers, management believes there would be no lapse in service if there were a change in electrical power suppliers. However, such a change might result in a higher cost of power to the Cooperative and, in turn, higher billing rates to its members.

The amount payable for purchased power to AEPCO is $3,414,299 and $3,524,310 at December 31, 2010 and 2009, respectively. The amount payable for purchased power to TRANSCO is $550,221 and $593,362 at December 31, 2010 and 2009, respectively.

Other related party transactions consisted of normal routine business conducted through organizations of which the Cooperative is a member and normal sales to its members.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

COMMITMENTS

The Cooperative is an Arizona Electric Power Cooperative, Inc. (AEPCO) partial requirements customer. As a continuing Class A member of AEPCO, which is a not-for-profit generation and transmission cooperative, the Cooperative is entitled to representation on the board of directors of AEPCO and its affiliated corporations. The Cooperative, under the terms of an agreement with AEPCO and in consideration of payments of a fixed monthly capacity charge and fixed demand and energy charge, is entitled to 35.8% of the AEPCO resources, including transmission and allocated demand and usage levels. The Cooperative has the contractual ability to resell AEPCO-provided resources in excess of the Cooperative's needs and not used by the Cooperative. The Cooperative's demand requirements beyond AEPCO's allocated resources are met through AES aggregation, other purchase power contracts, and open market purchases. The contract has no expiration date per se, but can be terminated by either party with notification as stipulated in the agreement.

In order to meet its demand requirements, the Cooperative entered into a Transmission Agreement with TRANSCO, an Arizona not-for-profit transmission cooperative corporation resulting from the restructuring of AEPCO. The Cooperative uses the Transmission Agreement to meet its demand usage requirements, with obligations to pay TRANSCO based on specified formulas. The agreement expires October 10, 2020.

The Cooperative has a three-party contract with a customer and AEPCO that states that any ACC-approved changes in AEPCO rates billed to the Cooperative will be passed through to the customer. The rates billed under the customer contract have not been, and may or may not be, adjusted to reflect the new rate structure under the Partial Requirements Capacity and Energy Agreement (PRECA). Management believes the total rates currently being charged to the customer are appropriate. Upon customer request, the Cooperative and AEPCO intend to negotiate with the customer regarding the impact of the PRECA on the rates being charged to the customer. No amounts have been recorded in the financial statements for any possible over or under recovery resulting from the different rate structures.

LITIGATION

The Cooperative is involved in various legal matters that management considers to be in the normal course of business. The Cooperative is also involved in litigation involving a former officer of the Cooperative. The outcome of these various matters is unknown. Therefore, nothing is recorded in the financial statements.

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

December 31, 2010 and 2009

SUBSEQUENT EVENTS

Management has made an evaluation of subsequent events and transactions for the period December 31, 2010 through the date of the audit report and determined that there were no material events that would require recognition or disclosure in the financial statements under SFAS No. 165, Subsequent Events, as codified at FASB ASC 855-10.

INDEPENDENT AUDITORS' REPORT ON COMPLIANCE WITH LAWS AND REGULATIONS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

We have audited the financial statements of Mohave Electric Cooperative, Inc. as of and for the year ended December 31, 2010, and have issued our report thereon dated May 17, 2011. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance

As part of obtaining reasonable assurance about whether Mohave Electric Cooperative, Inc.'s financial statements are free of material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance that are required to be reported under Government Auditing Standards.

Internal Control Over Financial Reporting

In planning and performing our audit, we considered Mohave Electric Cooperative, Inc.'s control over financial reporting as a basis for designing our auditing procedures for the purpose of expressing an opinion on the financial statements and not for the purpose of expressing an opinion on the effectiveness of the internal control over financial reporting. Accordingly, we do not express an opinion on the effectiveness of Mohave Electric Cooperative, Inc.'s internal control over financial reporting.

The Board of Directors
Mohave Electric Cooperative, Inc.
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Our consideration of internal control was for the limited purpose described in the preceding paragraph and would not necessarily identify all deficiencies in internal control over financial reporting that might be significant deficiencies or material weaknesses. A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the financial statements will not be prevented, or detected, by the entity's internal control. We noted no matters involving the internal control over financial reporting and its operation that we consider to be material weaknesses.

This communication is intended solely for the information and use of the audit committee, management, the Rural Utilities Service, and supplemental lenders, and is not intended to be, and should not be, used by anyone other than these specified parties.

Dreyer & Kelso, P.C., P.A.

May 17, 2011

MOHAVE ELECTRIC COOPERATIVE, INC.

SCHEDULE OF FINDINGS AND QUESTIONED COSTS AND UNRESOLVED PRIOR FINDINGS

FOR THE YEAR ENDED DECEMBER 31, 2010

SUMMARY OF AUDIT RESULTS

Financial Statements

Type of auditors' report issued:	unqualified
Internal control over financial reporting:	
Material weaknesses identified:	none
Significant deficiencies identified that are not considered to be material weaknesses:	none

SUPPLEMENTAL INFORMATION

**INDEPENDENT AUDITORS' REPORT
ON SUPPLEMENTAL INFORMATION**

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

The report on our audit of the basic financial statements of Mohave Electric Cooperative, Inc. for the year ended December 31, 2010 appears on page 1. This audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental information that follows is presented for purposes of additional analysis, and is not a required part of the basic financial statements. In addition, the accompanying schedule of federal awards is presented for purposes of additional analysis as required by U.S. Office of Management and Budget Circular A-133, Audits of States, Local Governments, and Non-Profit Organizations, and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Dreyer & Kelso, P.C., P.A.

May 17, 2011

REPORT ON COMPLIANCE WITH REQUIREMENTS APPLICABLE TO EACH MAJOR PROGRAM AND ON INTERNAL CONTROL OVER COMPLIANCE IN ACCORDANCE WITH OMB CIRCULAR A-133

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

Compliance

We have audited the compliance of Mohave Electric Cooperative, Inc. with the types of compliance requirements described in the U.S. Office of Management and Budget (OMB) Circular A-133 Compliance Supplement that are applicable to its major federal programs for the year ended December 31, 2010. Mohave Electric Cooperative, Inc.'s major federal program is identified in the summary of auditors' results section of the accompanying schedule of findings and questioned costs. Compliance with the requirements of laws, regulations, contracts, and grants applicable to its major federal programs is the responsibility of Mohave Electric Cooperative, Inc.'s management. Our responsibility is to express an opinion on Mohave Electric Cooperative, Inc.'s compliance based on our audit.

We conducted our audit of compliance in accordance with auditing standards generally accepted in the United States of America; the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States, and OMB Circular A-133, Audits of States, Local Governments, and Non-Profit Organizations. Those standards and OMB Circular A-133 require that we plan and perform the audit to obtain reasonable assurance about whether noncompliance with the types of compliance requirements referred to above that could have a direct and material effect on a major federal program occurred. An audit includes examining, on a test basis, evidence about whether Mohave Electric Cooperative, Inc.'s compliance with those requirements and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion. Our audit does not provide a legal determination of Mohave Electric Cooperative, Inc.'s compliance with those requirements.

In our opinion Mohave Electric Cooperative, Inc. complied, in all material respects, with the requirements referred to above that are applicable to its major federal programs identified in the accompanying schedule of findings and questioned costs for the year ended December 31, 2010.

The Board of Directors
Mohave Electric Cooperative, Inc.
Page Two

Internal Control Over Compliance

The management of Mohave Electric Cooperative, Inc. is responsible for establishing and maintaining effective internal control over compliance with the requirements of laws, regulations, contracts, and grants applicable to federal programs. In planning and performing our audit, we considered Mohave Electric Cooperative, Inc.'s internal control over compliance with requirements that could have a direct and material effect on a major federal program in order to determine our auditing procedures for the purpose of expressing our opinion on compliance and to test and report on internal control over compliance in accordance with OMB Circular A-133, but not for the purpose of expressing an opinion on the effectiveness of internal control over compliance. Accordingly, we do not express an opinion of the effectiveness of Mohave Electric Cooperative, Inc.'s internal control over compliance.

A deficiency in internal control over compliance exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, noncompliance with a type of compliance requirement of a federal program on a timely basis.

A material weakness in internal control over compliance is a significant deficiency, or combination of deficiencies in internal control over compliance, such that there is a reasonable possibility that material noncompliance with a type of compliance requirement of a federal program will not be prevented, or detected and corrected, by the entity's internal control.

Our consideration of internal control over compliance was for the limited purpose described in the first paragraph of this section and would not necessarily identify all deficiencies in internal control over compliance that might be deficiencies, significant deficiencies or material weaknesses. We did not identify any deficiencies in internal control over compliance that we consider to be material weaknesses, as defined above.

This report is intended solely for the information and use of the Board of Directors, management, the Rural Utilities Service, supplemental lenders, federal awarding agencies and pass-through entities and is not intended to be, and should not be, used by anyone other than these specified parties.

Dreyer & Kelso, P.C., P.A.

May 17, 2011

MOHAVE ELECTRIC COOPERATIVE, INC.

SCHEDULE OF FEDERAL AWARDS

FOR THE YEAR ENDED DECEMBER 31, 2010

Federal Grantor/Pass-Through Grantor/Program or Cluster Title	Federal CFDA Number	Pass-Through Entity Identifying Number	Federal Expenditures
Department of Energy			
Electricity Delivery and Energy Reliability, Research, Development And Analysis	81.122	DE-OE0000451	$3,537,596
State Energy Program	81.041	1059-09-07	823,519
Total Expenditures of Federal Awards			$4,361,115
Total Cash Receipts for Both Programs			$1,154,255
Total Expenditures over Cash Receipts			$3,206,860

MOHAVE ELECTRIC COOPERATIVE, INC.

NOTES TO SCHEDULE OF FEDERAL AWARDS

FOR THE YEAR ENDED DECEMBER 31, 2010

BASIS OF PRESENTATION

The accompanying schedule of federal awards (Schedule) includes the federal grant activity of Mohave Electric Cooperative, Inc. (Cooperative) for the year ended December 31, 2010. The information in this schedule is presented in accordance with the requirements of the Office of Management and Budget (OMB) Circular A-133, *Audits of States, Local Governments, and Non-Profit Organizations*. Because the schedule presents only a selected portion of the operations of Mohave Electric Cooperative, Inc., it is not intended to and does not present the financial position, results of operations, and cash flows of Mohave Electric Cooperative, Inc.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Receipts and expenditures on the Schedule are reported on the modified accrual basis of accounting. Receipts are presented on a cash basis and the expenditures are recognized on the accrual basis and following the cost principles contained in OMB Circular A-122, *Cost Principles for Non-profit Organizations*, wherein certain types of expenditures are not allowable or are limited as to reimbursement. The Cooperative is a sub-recipient of Southwest Transmission Cooperative, Inc. (pass-through entity).

MOHAVE ELECTRIC COOPERATIVE, INC.

SCHEDULE OF FINDINGS AND QUESTIONED COSTS

FOR THE YEAR ENDED DECEMBER 31, 2010

SUMMARY OF AUDIT RESULTS

Financial Statements

Type of auditors' report issued:	unqualified
Internal control over financial reporting:	
Material weaknesses identified:	none
Significant deficiencies identified that are not considered to be material weaknesses:	none

Federal Awards

Internal control over major program:	
Material weaknesses identified:	none
Significant deficiencies identified that are not considered to be material weaknesses:	none
Type of auditors' report issued on compliance for major program:	unqualified
Any audit findings disclosed that are required to be reported in accordance with section 501(a) of Circular A-133:	none

Major Program:

CFDA Number	Name of Federal Program
81.122	Department of Energy - Electricity Delivery and Energy Reliability, Research, Development and Analysis

Auditee did not qualify as a low-risk auditee.

MOHAVE ELECTRIC COOPERATIVE, INC.

SCHEDULE OF FINDINGS AND QUESTIONED COSTS

FOR THE YEAR ENDED DECEMBER 31, 2010

SUMMARY OF AUDIT RESULTS

Financial Statements

Type of auditors' report issued:	unqualified
Internal control over financial reporting:	
Material weaknesses identified:	none
Significant deficiencies identified that are not considered to be material weaknesses:	none

Federal Awards

Internal control over major program:	
Material weaknesses identified:	none
Significant deficiencies identified that are not considered to be material weaknesses:	none
Type of auditors' report issued on compliance for major program:	unqualified
Any audit findings disclosed that are required to be reported in accordance with section 501(a) of Circular A-133:	none

Major Program:

CFDA Number	Name of Federal Program
81.041	Department of Energy - State Energy Program

Auditee did not qualify as a low-risk auditee.

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

We have audited the financial statements of Mohave Electric Cooperative, Inc. for the year ended December 31, 2010, and have issued our report thereon dated May 17, 2011. We conducted our audit in accordance with generally accepted auditing standards, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States, and 7 CFR Part 1773, Policy on Audits of Rural Utilities Service (RUS) Borrowers. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing our audit of the financial statements of Mohave Electric Cooperative, Inc. for the year ended December 31, 2010, in accordance with auditing standards generally accepted in the United States of America, we considered Mohave Electric Cooperative, Inc.'s internal control over financial reporting (internal control) as a basis for designing our auditing procedures for the purpose of expressing an opinion on the financial statements and not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control. Accordingly, we do not express an opinion of the effectiveness of the Cooperative's internal control.

Our consideration of the internal control was for the limited purpose described in the preceding paragraph and would not necessarily identify all deficiencies in internal control that might be significant deficiencies or material weaknesses. A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the financial statements will not be prevented, or detected, by the Cooperative's internal control. We noted no matters involving the internal control over financial reporting and its operation that we consider to be material weaknesses.

7 CFR Part 1773.33 requires comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, and other additional matters. We have grouped our comments accordingly. In addition to obtaining reasonable assurance about whether the financial statements are free from material misstatements, at your request, we performed tests of specific aspects of the internal control over financial reporting, of compliance with specific RUS loan and security instrument provisions, and of additional matters. The specific aspects of the internal control over financial reporting,

compliance with specific RUS loan and security instrument provisions, and additional matters tested include, among other things, the accounting procedures and records, materials control, compliance with specific RUS loan and security instrument provisions set forth in 7 CFR Part 1773.33(e)(l), related party transactions, depreciation rates, and a schedule of deferred charges and credits, and a schedule of investments, upon which we express an opinion. In addition, our audit of the financial statements also included the procedures specified in 7 CFR Part 1773.38 - .45. Our objective was not to provide an opinion on these specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, or additional matters, and accordingly, we express no opinion thereon.

No reports (other than our independent auditors' report and our independent auditors' report on compliance and internal control over financial reporting all dated May 17, 2011) or summary of recommendations related to our audit have been furnished to management.

Our comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters as required by 7 CFR Part 1773.33 are presented below.

COMMENTS ON CERTAIN SPECIFIC ASPECTS OF THE INTERNAL CONTROL OVER FINANCIAL REPORTING

We noted no matters regarding Mohave Electric Cooperative, Inc.'s internal control over financial reporting and its operation that we consider to be a material weakness as previously defined with respect to:

the accounting procedures and records;

the process for accumulating and recording labor, material and overhead costs, and the distribution of these costs to construction, retirement, and maintenance or other expense accounts; and

the materials control.

COMMENTS ON COMPLIANCE WITH SPECIFIC RUS LOAN AND SECURITY INSTRUMENT PROVISIONS

At your request, we have performed the procedures enumerated below with respect to compliance with certain provisions of laws, regulations, contracts, and grants. The procedures we performed are summarized as follows:

Procedures performed with respect to the requirement for a borrower to obtain written approval of the mortgagee to enter into any contract for the operation or maintenance of property, or for the use of mortgaged property by others for the year ended December 31, 2010 of Mohave Electric Cooperative, Inc.:

Obtained and read a borrower-prepared schedule of new written contracts entered into during the year for the operation or maintenance of its property, or for the use of its property by others as defined in 7 CFR 1773.33(e)(1)(i).

Reviewed Board of Directors minutes to ascertain whether board-approved written contracts are included in the borrower-prepared schedule.

Noted the existence of written RUS (and other mortgagee) approval of each contract listed by the borrower.

Procedure performed with respect to the requirement to submit RUS Form 7 to the RUS:

Agreed amounts reported in Form 7 to Mohave Electric Cooperative, Inc.'s records.

The results of our tests indicate that, with respect to the items tested, Mohave Electric Cooperative, Inc. complied, in all material respects, with the specific RUS loan and security instrument provisions referred to below. The specific provisions tested, as well as any exceptions noted, include the requirements that:

the borrower has obtained written approval from RUS (and other mortgagees) to enter into any contract for the operation or maintenance of property, or for the use of mortgaged property by others as defined in 7 CFR Part 1773.33(e)(1)(i); and,

the borrower has submitted its Form 7 to the RUS and the Form 7, Financial and Statistical Report as of December 31, 2010, represented by the borrower as having been submitted to RUS, appears reasonable based upon the audit procedures performed.

COMMENTS ON OTHER ADDITIONAL MATTERS

In connection with our audit of the financial statements of Mohave Electric Cooperative, Inc., nothing came to our attention that caused us to believe that Mohave Electric Cooperative, Inc. failed to comply with respect to:

the reconciliation of continuing property records to the controlling general ledger plant accounts addressed at 7 CFR Part 1773.33(c)(1);

the clearing of construction accounts and the accrual of depreciation on completed construction addressed at 7 CFR Part 1773.33(c)(2);

the retirement of plant addressed at 7 CFR Part 1773.33(c)(3) and (4);

approval of the sale, lease, or transfer of capital assets and disposition of proceeds for the sale or lease of plant, material, or scrap addressed at 7 CFR Part 1773.33 (c)(5);

the disclosure of material related party transactions in accordance with Statement of Financial Accounting Standards No. 57, Related Party Transactions, for the year ended December 31, 2010 in the financial statements referenced in the first paragraph of this report addressed at 7 CFR Part 1773.33(f);

the depreciation rates addressed at 7 CFR Part 1773.33(g);

the detailed schedule of deferred charges and deferred credits addressed at 7 CFR Part 1773.33(h); and

the detailed schedule of investments addressed at 7 CFR Part 1773.33(i).

DETAILED SCHEDULE OF DEFERRED CHARGES, DEFERRED CREDITS AND INVESTMENTS

Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The detailed schedule of deferred charges and deferred credits required by 7 CFR Part 1773.33(h), and the detailed schedule of investments required by 7 CFR Part 1773.33(i), and provided below are presented for purposes of additional analysis and are not a required part of the basic financial statements. This information has been subjected to the auditing procedures applied in our audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Detailed Schedule of Deferred Charges, Deferred Credits, and Investments

Deferred Charges

Past Service Pension Cost	$ 607,941
Construction Advances	13,705,566
Preliminary Survey and Investigation	47,082
Work Plans	127,410
Undistributed Transportation Expense	575
Other Deferred Charges	(9,353)
Total Deferred Charges	$ 14,479,221

Deferred Credits

Customers' Prepayments	$ 805,439
Customers' Advances for Construction	3,868,870
Deferred Gain-Sale of DirecTV Rights	1,214,052
Deferred Revenue Assessments	974,861
Accumulated Over-Recovery of Power Cost	9,145,832
Other Deferred Credits	163,366
Total Deferred Credits	$16,172,420

Investments

None Required To Be Reported

This report is intended solely for the information and use of the board of directors, management, the Rural Utilities Service, and supplemental lenders, and is not intended to be, and should not be, used by anyone other than these specified parties.

Dreyer & Kelso, P.C., P.A.

May 17, 2011

The Board of Directors
Mohave Electric Cooperative, Inc.
Bullhead City, AZ

We have audited the financial statements of Mohave Electric Cooperative, Inc. the year ended December 31, 2010, and have issued our report thereon dated May 17, 2011. Professional standards require that we provide you with the following information related to our audit.

The Auditors' Responsibility Under U.S. Generally Accepted Auditing Standards

As stated in our engagement letter dated September 29, 2010, our responsibility, as described by professional standards, is to plan and perform our audit to obtain reasonable, but not absolute, assurance that the financial statements are free of material misstatement and to express an opinion about whether the financial statements prepared by management with your oversight are fairly presented, in all material respects, in accordance with U.S. generally accepted accounting principles. Because an audit is designed to provide reasonable, but not absolute, assurance and because we did not perform a detailed examination of all transactions, there is a risk that material errors, irregularities, or illegal acts, including fraud and defalcations, may exist and not be detected by us.

As part of our audit, we considered the internal control of Mohave Electric Cooperative, Inc. Such considerations were solely for the purpose of determining our audit procedures and not to provide any assurance concerning such internal control. We are responsible for communicating significant matters related to the audit that are, in our professional judgment, relevant to your responsibilities in overseeing the financial reporting process. However, we are not required to design procedures specifically to identify such matters.

Planned Scope and Timing of Audit

We performed the audit according to the planned scope and timing previously communicated to you in our correspondence about planning matters.

Significant Audit Findings

Management has the responsibility for selection and use of appropriate accounting policies. In accordance with the terms of our engagement letter, we will advise management about the appropriateness of accounting policies and their application. The significant accounting policies used by the Cooperative are described in the notes to the financial statements. Management has informed us that no new accounting policies were adopted and the application of existing policies was not changed during the year ended December 31, 2010. We noted no transactions entered into by the Cooperative during the year for which there is a lack of authoritative guidance or consensus. There are no significant transactions that have been recognized in the financial statements in a different period than when the transaction occurred.

Accounting Estimates

Accounting estimates are an integral part of the financial statements prepared by management and are based on management's knowledge and experience about past and current events and assumptions about future events. Certain accounting estimates are particularly sensitive because of their significance to the financial statements and because of the possibility that future events affecting them may differ significantly from those expected.

One of the significant accounting estimates affecting the Cooperative's financial statements is the estimated useful lives of the Utility Plant for purposes of computing depreciation. We eva'uated the estimated useful lives used by management for the transmission, distribution and general plant in determining that they are reasonable in relation to the financial statements taken as a whole.

There are no other accounting estimates that are significant to the financial statements taken as a whole.

Financial Statement Disclosures

The disclosures in the financial statements are neutral, consistent, and clear. Certain financial statement disclosures are particularly sensitive because of their significance to financial statement users. There are no financial statement disclosures that are sensitive and significant to the financial statements taken as a whole.

Corrected and Uncorrected Misstatements

Professional standards require us to accumulate all known and likely misstatements identified during the audit, other than those that are trivial, and communicate them to the appropriate level of management.

During the audit certain adjustments were identified and evaluated that management has determined their effects to be immaterial, both individually and in the aggregate, to the financial statements taken as a whole. A copy of these uncorrected misstatements is attached for your review.

Management Representations

We have requested certain representations from management that are included in the management representation letter.

Disagreements with Management

For purposes of this letter, professional standards define a disagreement with management as a matter, whether or not resolved to our satisfaction, concerning a financial accounting, reporting, or auditing matter that could be significant to the financial statements or the auditors' report. We are pleased to report that no such disagreements arose during the course of our audit.

Difficulties Encountered in Performing The Audit

We encountered no significant difficulties in dealing with management in performing and completing our audit.

Other Findings or Issues

We generally discuss a variety of matters, including the application of accounting principles and auditing standards, with management each year prior to retention as the Cooperative's auditors. However, these discussions occurred in the normal course of our professional relationship and our responses were not a condition to our retention.

This report is intended for the use of the Board of Directors and management of Mohave Electric Cooperative, Inc. and should not be used for any other purpose.

If you have any questions or comments regarding the items discussed in this letter, or any others, please allow us to be of assistance.

We would like to express our thanks for the courtesy and assistance once again extended to us during the course of our audit.

Dreyer & Kelso, P.C., P.A.

May 17, 2011

MOHAVE ELECTRIC COOPERATIVE, INC.

UNCORRECTED MISSTATEMENTS

December 31, 2010

Account #	Account Name/Description	Charges	Credits
	#1		
253.10	CONSUMER ENERGY PREPAYMENTS	$115,789.43	
142.00	CUSTOMER ACCOUNTS RECEIVABLE		$115,789.43
	TO ADJUST CONSUMER ENERGY PREPAYMENTS.		
	#2		
921.00	OFFICE SUPPLIES AND EXPENSES	30,918.00	
253.30	DEFERRED CREDITS - MISCELLANEOUS		30,918.00
	TO WRITE OFF THE DEFERRED CREDIT.		
	#3		
923.11	OUTSIDE SERVICES - LEGAL FEES	134,447.66	
232.10	ACCOUNTS PAYABLE - GENERAL		134,447.66
	TO RECORD UNRECORDED LEGAL EXPENSE.		
	#4		
186.20	DEFERRED DEBITS - OTHER	32,192.12	
253.12	DEFERRED CR-ENV PORTFOLIO SURCHARGE	48,727.30	
232.10	ACCOUNTS PAYABLE - GENERAL		80,919.42
	TO RECORD UNRECORDED LIABILITIES.		

MOHAVE ELECTRIC COOPERATIVE, INC.

UNCORRECTED MISSTATEMENTS

December 31, 2010

Account #	Account Name/Description	Charges	Credits
	#5		
403.70	DEPRN EXPENSE - GENERAL PLANT	$103,379.37	
108.76	ACCUM DEPRN - POWER TOOLS		$103,379.37
	TO ADJUST ACCUMULATED DEPRECIATION FOR EXCESS TAKEN.		
		$465,453.88	**$465,453.88**

Supplemental Section M

2010 Form 7

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION AZ0022
FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION	PERIOD ENDED December, 2010 (Prepared with Audited Data)
INSTRUCTIONS - See help in the online application.	BORROWER NAME Mohave Electric Cooperative, Incorporated

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552)

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

[X] All of the obligations under the RUS loan documents have been fulfilled in all material respects.

[ ] There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part D of this report.

John Carlson 5/17/2011

DATE

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	72,374,613	70,517,805	70,746,904	4,643,324
2. Power Production Expense				
3. Cost of Purchased Power	58,273,522	56,294,063	57,249,237	3,606,147
4. Transmission Expense	374,367	169,400	383,418	9,302
5. Regional Market Expense				
6. Distribution Expense - Operation	2,407,214	2,773,698	2,100,627	253,305
7. Distribution Expense - Maintenance	1,397,297	1,194,657	1,197,540	108,321
8. Customer Accounts Expense	2,332,076	2,227,246	2,183,822	216,479
9. Customer Service and Informational Expense	149,340	196,226	150,444	4,026
10. Sales Expense	121,191	96,252	126,317	(11,463)
11. Administrative and General Expense	4,301,235	4,756,463	3,667,638	884,078
12. Total Operation & Maintenance Expense (*2 thru 11*)	69,356,242	67,708,005	67,059,043	5,070,195
13. Depreciation and Amortization Expense	2,176,551	2,239,666	2,499,544	205,925
14. Tax Expense - Property & Gross Receipts				
15. Tax Expense - Other				
16. Interest on Long-Term Debt	2,208,733	2,161,308	2,088,812	185,867
17. Interest Charged to Construction - Credit				
18. Interest Expense - Other	118,932	142,396	126,000	13,422
19. Other Deductions	7,397	17,024	6,950	(184)
20. Total Cost of Electric Service (*12 thru 19*)	73,867,855	72,268,399	71,780,349	5,475,225
21. Patronage Capital & Operating Margins (*1 minus 20*)	(1,493,242)	(1,750,594)	(1,033,445)	(831,901)
22. Non Operating Margins - Interest	499,868	410,049	468,653	120,019
23. Allowance for Funds Used During Construction				
24. Income (Loss) from Equity Investments	110,369	110,369		110,369
25. Non Operating Margins - Other	4,256	(32,307)		
26. Generation and Transmission Capital Credits	6,340,428	3,509,969	5,500,000	0
27. Other Capital Credits and Patronage Dividends	158,148	107,687	159,000	18,546
28. Extraordinary Items				
29. Patronage Capital or Margins (*21 thru 28*)	5,619,827	2,355,173	5,094,208	(582,967)

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	255	175	5. Miles Transmission	108.59	108.59
2. Services Retired	28	31	6. Miles Distribution – Overhead	1,055.27	1,054.90
3. Total Services in Place	43,269	43,413	7. Miles Distribution - Underground	345.60	348.55
4. Idle Services (*Exclude Seasonals*)	4,693	4,685	8. **Total Miles Energized** *(5 + 6 + 7)*	1,509.46	1,512.04

PART C. BALANCE SHEET

ASSETS AND OTHER DEBITS			LIABILITIES AND OTHER CREDITS		
1.	Total Utility Plant in Service	88,890,934	30.	Memberships	162,045
2.	Construction Work in Progress	3,021,375	31.	Patronage Capital	65,209,945
3.	**Total Utility Plant** *(1 + 2)*	91,912,309	32.	Operating Margins - Prior Years	0
4.	Accum. Provision for Depreciation and Amort.	35,708,314	33.	Operating Margins - Current Year	1,867,062
5.	**Net Utility Plant** *(3 - 4)*	56,203,995	34.	Non-Operating Margins	488,111
6.	Non-Utility Property (Net)	0	35.	Other Margins and Equities	2,075,368
7.	Investments in Subsidiary Companies	0	36.	**Total Margins & Equities** *(30 thru 35)*	69,802,531
8.	Invest. in Assoc. Org. - Patronage Capital	30,020,881	37.	Long-Term Debt - RUS (Net)	13,831,450
9.	Invest. in Assoc. Org. - Other - General Funds	2,003,515	38.	Long-Term Debt - FFB - RUS Guaranteed	16,789,142
10.	Invest. in Assoc. Org. - Other - Nongeneral Funds	802,850	39.	Long-Term Debt - Other - RUS Guaranteed	6,829,623
11.	Investments in Economic Development Projects	0	40.	Long-Term Debt Other (Net)	0
12.	Other Investments	0	41.	Long-Term Debt - RUS - Econ. Devel. (Net)	0
13.	Special Funds	986,398	42.	Payments – Unapplied	0
14.	**Total Other Property & Investments** *(6 thru 13)*	33,813,644	43.	**Total Long-Term Debt** *(37 thru 41 - 42)*	37,450,215
15.	Cash - General Funds	1,651,369	44.	Obligations Under Capital Leases - Noncurrent	0
16.	Cash - Construction Funds - Trustee	0	45.	Accumulated Operating Provisions and Asset Retirement Obligations	0
17.	Special Deposits	0	46.	**Total Other Noncurrent Liabilities** *(44 + 45)*	0
18.	Temporary Investments	18,719,063	47.	Notes Payable	0
19.	Notes Receivable (Net)	2,119,400	48.	Accounts Payable	5,659,565
20.	Accounts Receivable - Sales of Energy (Net)	3,666,917	49.	Consumers Deposits	2,732,714
21.	Accounts Receivable - Other (Net)	1,738,201			
22.	Renewable Energy Credits	0	50.	Current Maturities Long-Term Debt	1,690,592
23.	Materials and Supplies - Electric & Other	2,115,530	51.	Current Maturities Long-Term Debt - Economic Development	0
24.	Prepayments	8,769,582	52.	Current Maturities Capital Leases	0
25.	Other Current and Accrued Assets	195,766	53.	Other Current and Accrued Liabilities	10,675,820
26.	**Total Current and Accrued Assets** *(15 thru 25)*	38,975,828	54.	**Total Current & Accrued Liabilities** *(47 thru 53)*	20,758,691
27.	Regulatory Assets	0	55.	Regulatory Liabilities	0
28.	Other Deferred Debits	6,271,084	56.	Other Deferred Credits	7,253,114
29.	**Total Assets and Other Debits** *(5+14+26 thru 28)*	135,264,551	57.	**Total Liabilities and Other Credits** *(36 + 43 + 46 + 54 thru 56)*	135,264,551

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION *AZ0022*
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010

PART D. NOTES TO FINANCIAL STATEMENTS

Re: Mortgage Ratio Check Warnings

Mohave Electric Cooperative filed an application for a rate increase with the Arizona Corporation Commission on Wednesday, March 30, 2011.

The Cooperative is aware that the existing 20-year old rates are inadequate. With the economic slowdown the Cooperative's revenues have not been able to sustain its operating costs through constant growth in its consumer base as it had in the past. In addition, the Cooperative's competitive rates for resale sales were lower due to the cooperative's purchased power cost. Our sale prices were not competitive in the resale market. In the past the market allowed the Cooperative ample resale opportunity to recoup its power cost with a modest margin to help sustain operating costs and avoid rate increases.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010
PART D. CERTIFICATION LOAN DEFAULT NOTES	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC DISTRIBUTION

BORROWER DESIGNATION AZ0022

PERIOD ENDED December, 2010

NSTRUCTIONS - See help in the online application.

PART E. CHANGES IN UTILITY PLANT

PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
. Distribution Plant	68,073,168	543,146	58,607	55,263	68,612,970
:. General Plant	4,858,626	174,822	303,224	(2,860)	4,727,364
;. Headquarters Plant	4,253,305	107,489	10,925		4,349,869
I. Intangibles	579				579
;. Transmission Plant	11,182,867	17,319	34		11,200,152
;. Regional Transmission and Market Operation Plant					
'. All Other Utility Plant	0				0
I. **Total Utility Plant in Service (*1 thru 7*)**	88,368,545	842,776	372,790	52,403	88,890,934
). Construction Work in Progress	428,827	2,592,548			3,021,375
.0. **Total Utility Plant (*8 + 9*)**	88,797,372	3,435,324	372,790	52,403	91,912,309

PART F. MATERIALS AND SUPPLIES

ITEM	BALANCE BEGINNING OF YEAR (a)	PURCHASED (b)	SALVAGED (c)	USED (NET) (d)	SOLD (e)	ADJUSTMENT (f)	BALANCE END OF YEAR (g)
. Electric	2,132,277	457,935	0	446,232	0	(28,450)	2,115,530
:. Other	0						0

PART G. SERVICE INTERRUPTIONS

ITEM	AVERAGE MINUTES PER CONSUMER BY CAUSE				
	POWER SUPPLIER (a)	MAJOR EVENT (b)	PLANNED (c)	ALL OTHER (d)	TOTAL (e)
. Present Year	25.510	60.060	.200	54.700	140.470
:. Five-Year Average	40.270	87.760	.880	55.750	184.660

PART H. EMPLOYEE-HOUR AND PAYROLL STATISTICS

. Number of Full Time Employees	85	4. Payroll - Expensed	4,313,704
:. Employee - Hours Worked - Regular Time	172,746	5. Payroll – Capitalized	492,969
;. Employee - Hours Worked - Overtime	4,059	6. Payroll - Other	94,584

PART I. PATRONAGE CAPITAL

ITEM	DESCRIPTION	THIS YEAR (a)	CUMULATIVE (b)
. Capital Credits - Distributions	a. General Retirements	0	5,445,821
	b. Special Retirements	243,588	3,854,337
	c. **Total Retirements (*a + b*)**	243,588	9,300,158
:. Capital Credits - Received	a. Cash Received From Retirement of Patronage Capital by Suppliers of Electric Power	0	
	b. Cash Received From Retirement of Patronage Capital by Lenders for Credit Extended to the Electric System	34,479	
	c. **Total Cash Received (*a + b*)**	34,479	

PART J. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

. Amount Due Over 60 Days	$ 73,947	2. Amount Written Off During Year	$ 289,422

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application	PERIOD ENDED December, 2010

PART K. kWh PURCHASED AND TOTAL COST

No	ITEM (a)	RUS USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	kWh PURCHASED (e)	TOTAL COST (f)	AVERAGE COST (Cents/kWh) (g)	INCLUDED IN TOTAL COST - FUEL COST ADJUSTMENT (h)	INCLUDED IN TOTAL COST - WHEELING AND OTHER CHARGES (i)
1	Arizona Electric Pwr Coop, Inc (AZ0028)	796			657,399,000	52,700,660	8.02	11,808,216	7,285,268
2	Powerex	800228			10,472,000	763,682	7.29		8,256
3	JP Morgan Venture Energy (NY)	800499			2,080,000	93,680	4.50		1,640
4	Western Area Power Admin	27000			5,352,000	787,616	14.72		481,130
5	*Miscellaneous	700000			49,846,471	1,948,424	3.91		62,844
	Total				725,149,471	56,294,062	7.76	11,808,216	7,839,138

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application	PERIOD ENDED December, 2010

PART K. kWh PURCHASED AND TOTAL COST

No	Comments
1	
2	
3	
4	
5	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010

PART L. LONG-TERM LEASES

No	NAME OF LESSOR (a)	TYPE OF PROPERTY (b)	RENTAL THIS YEAR (c)
	TOTAL		

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022		
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010		

PART M. ANNUAL MEETING AND BOARD DATA

1. Date of Last Annual Meeting	2. Total Number of Members	3. Number of Members Present at Meeting	4. Was Quorum Present?
6/25/2010	32,207	132	Y
5. Number of Members Voting by Proxy or Mail	**6. Total Number of Board Members**	**7. Total Amount of Fees and Expenses for Board Members**	**8. Does Manager Have Written Contract?**
	9	$ 168,943	N

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010

PART N. LONG-TERM DEBT AND DEBT SERVICE REQUIREMENTS

No	ITEM	BALANCE END OF YEAR (a)	INTEREST (Billed This Year) (b)	PRINCIPAL (Billed This Year) (c)	TOTAL (Billed This Year) (d)
1	Rural Utilities Service (Excludes RUS - Economic Development Loans)	13,831,450	763,666	954,373	1,718,039
2	National Rural Utilities Cooperative Finance Corporation	5,196,566	426,362	358,626	784,988
3	CoBank, ACB	1,633,057	123,198	31,623	154,821
4	Federal Financing Bank	16,789,142	848,082	280,127	1,128,209
5	RUS - Economic Development Loans				
6	Payments Unapplied				
	TOTAL	37,450,215	2,161,308	1,624,749	3,786,057

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022 PERIOD ENDED December, 2010
INSTRUCTIONS - See help in the online application.	

PART O. POWER REQUIREMENTS DATABASE - ANNUAL SUMMARY

CLASSIFICATION	CONSUMER SALES & REVENUE DATA	DECEMBER (a)	AVERAGE NO. CONSUMERS SERVED (b)	TOTAL YEAR TO DATE (c)
1. Residential Sales (excluding seasonal)	a. No. Consumers Served	34,735	34,672	
	b. kWh Sold			365,160,937
	c. Revenue			40,797,752
2. Residential Sales - Seasonal	a. No. Consumers Served			
	b. kWh Sold			
	c. Revenue			
3. Irrigation Sales	a. No. Consumers Served	23	23	
	b. kWh Sold			4,302,352
	c. Revenue			457,558
4. Comm. and Ind. 1000 KVA or Less	a. No. Consumers Served	3,940	3,947	
	b. kWh Sold			216,678,042
	c. Revenue			21,434,470
5. Comm. and Ind. Over 1000 KVA	a. No. Consumers Served	3	3	
	b. kWh Sold			69,006,000
	c. Revenue			5,214,014
6. Public Street & Highway Lighting	a. No. Consumers Served	16	16	
	b. kWh Sold			434,436
	c. Revenue			38,133
7. Other Sales to Public Authorities	a. No. Consumers Served			
	b. kWh Sold			
	c. Revenue			
8. Sales for Resale - RUS Borrowers	a. No. Consumers Served			
	b. kWh Sold			
	c. Revenue			
9. Sales for Resale - Other	a. No. Consumers Served	1	1	
	b. kWh Sold			46,862,961
	c. Revenue			1,826,810
10. Total No. of Consumers (*lines 1a thru 9a*)		38,718	38,662	
11. Total kWh Sold (*lines 1b thru 9b*)				702,444,728
12. Total Revenue Received From Sales of Electric Energy (*lines 1c thru 9c*)				69,768,737
13. Transmission Revenue				
14. Other Electric Revenue				749,068
15. kWh - Own Use				703,607
16. Total kWh Purchased				725,149,471
17. Total kWh Generated				
18. Cost of Purchases and Generation				56,463,463
19. Interchange - kWh - Net				
20. Peak - Sum All kW Input (Metered) Non-coincident X Coincident___				200,713

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION**	BORROWER DESIGNATION AZ0022
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2010

PART P. ENERGY EFFICIENCY PROGRAMS

CLASSIFICATION	ADDED THIS YEAR			TOTAL TO DATE		
	No. of Consumers *(a)*	Amount Invested *(b)*	Estimated MMBTU Savings *(c)*	No. of Consumers *(d)*	Amount Invested *(e)*	Estimated MMBTU Savings *(f)*
1. Residential Sales (excluding seasonal)						
2. Residential Sales - Seasonal						
3. Irrigation Sales						
4. Comm. and Ind. 1000 KVA or Less						
5. Comm. and Ind. Over 1000 KVA						
6. Public Street and Highway Lighting						
7. Other Sales to Public Authorities						
8. Sales for Resale – RUS Borrowers						
9. Sales for Resale – Other						
10. Total						

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION INVESTMENTS, LOAN GUARANTEES AND LOANS**	BORROWER DESIGNATION AZ0022 PERIOD ENDED December, 2010

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part C. Identify all investments in Rural Development with an 'X' in column (c). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

PART Q. SECTION I. INVESTMENTS (See Instructions for definitions of Income or Loss)

No	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RURAL DEVELOPMENT (e)
2	**Investments in Associated Organizations**				
	Federated Rural Insurance		109,280	14,464	
	ERMCO	76,731		1,592	
	CoBank	1,000			
	NRUCFC-CTC/LTC		802,850		
	ERMCO	100			
	CoBank		130,074	11,073	
	NRUCFC-Patr Cap Cr		345,457	23,406	
	Sierra S.W.	100			
	Southwest Transco	100			
	Grand Canyon State-Membership	100			
	Arizona Electric Power Coop		26,350,787		
	NRTC-Membership	1,000			
	Southwest Transco-Cap Cr		2,347,466		
	NRECA		659,608	11,548	
	NRUCFC-Member Cap Securities		2,000,000		
	NRUCFC-Membership	1,000			
	NISC-Patr Capital	1,479			
	NRECA-Membership	10			
	AEPCO-Membership	5			
	NISC-Membership	100			
	Totals	81,725	32,745,522	62,083	
5	**Special Funds**				
	Homestead Funds		226,526		
	Edward Jones Investments	509,872	250,000		
	Totals	509,872	476,526		
6	**Cash - General**				
	Working Funds		1,800		
	JPMORGAN Chase Bank		205,042		
	Mutual of Omaha Bank	1,194,527	250,000		
	Totals	1,194,527	456,842		
8	**Temporary Investments**				
	Mutual of Omaha Bank	18,469,063	250,000		
	Totals	18,469,063	250,000		
9	**Accounts and Notes Receivable - NET**				
	Accounts Receivable	1,738,201			
	Notes Receivable	2,119,400			
	Totals	3,857,601			
11	TOTAL INVESTMENTS (1 thru 10)	24,112,788	33,928,890	62,083	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION INVESTMENTS, LOAN GUARANTEES AND LOANS**	BORROWER DESIGNATION AZ0022 PERIOD ENDED December, 2010

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part C. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

PART Q. SECTION II. LOAN GUARANTEES

No	ORGANIZATION (a)	MATURITY DATE (b)	ORIGINAL AMOUNT ($) (c)	LOAN BALANCE ($) (d)	RURAL DEVELOPMENT (e)
	TOTAL				
	TOTAL (Included Loan Guarantees Only)				

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC DISTRIBUTION INVESTMENTS, LOAN GUARANTEES AND LOANS**	BORROWER DESIGNATION AZ0022 PERIOD ENDED December, 2010

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part C. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION III. RATIO

RATIO OF INVESTMENTS AND LOAN GUARANTEES TO UTILITY PLANT [Total of Included Investments (Section I, 11b) and Loan Guarantees - Loan Balance (Section II, 5d) to Total Utility Plant (Line 3, Part C) of this report]	26.24 %

SECTION IV. LOANS

No	ORGANIZATION (a)	MATURITY DATE (b)	ORIGINAL AMOUNT ($) (c)	LOAN BALANCE ($) (d)	RURAL DEVELOPMENT (e)
1	Employees, Officers, Directors	12/31/2018	100,000	80,000	
2	Energy Resources Conservation Loans				
	TOTAL		100,000	80,000	

SUPPLEMENTAL SCHEDULE N

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

		Billing	Proposed Rate			Proposed Revenue		
		Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE								
Residential								
Service Charge (12 Month Sum)		417,302	0.00	16.50	16.50	0	6,885,483	6,885,483
Energy Charge per kWh								
First	200 kWh per month	75,441,637	0.095280	0.001093	0.096373	7,188,079	82,458	7,270,537
Next	200 kWh per month	62,783,417	0.095280	0.001093	0.096373	5,982,004	68,622	6,050,626
Next	200 kWh per month	50,237,165	0.095280	0.011093	0.106373	4,786,597	557,281	5,343,878
Next	200 kWh per month	39,197,460	0.095280	0.011093	0.106373	3,734,734	434,817	4,169,551
Next	200 kWh per month	30,436,462	0.095280	0.011093	0.106373	2,899,986	337,632	3,237,618
Over	1,000 kWh per month	106,015,612	0.095280	0.021093	0.116373	10,101,168	2,236,187	12,337,355
Base Revenue		364,111,753				34,692,568	10,602,480	45,295,048
PPCA Revenue						(673,607)	0	(673,607)
Total Revenue						34,018,961	10,602,480	44,621,441
Residential - Seasonal								
Service Charge (12 Month Sum)		11	0.00	16.50	16.50	0	182	182
Energy Charge per kWh								
First	200 kWh per month	201	0.095280	0.001093	0.096373	19	0	19
Next	200 kWh per month	200	0.095280	0.001093	0.096373	19	0	19
Next	200 kWh per month	148	0.095280	0.011093	0.106373	14	2	16
Next	200 kWh per month	0	0.095280	0.011093	0.106373	0	0	0
Next	200 kWh per month	0	0.095280	0.011093	0.106373	0	0	0
Over	1,000 kWh per month	0	0.095280	0.021093	0.116373	0	0	0
Base Revenue		549				52	184	236
PPCA Revenue						(1)	0	(1)
Total Revenue						51	184	235
Residential - Net Metering								
Service Charge (12 Month Sum)		863	0.00	22.00	22.00	0	18,986	18,986
Energy Charge per kWh								
First	200 kWh per month	114,805	0.095280	0.001093	0.096373	10,939	125	11,064
Next	200 kWh per month	97,201	0.095280	0.001093	0.096373	9,261	106	9,368
Next	200 kWh per month	79,816	0.095280	0.011093	0.106373	7,605	885	8,490
Next	200 kWh per month	63,706	0.095280	0.011093	0.106373	6,070	707	6,777
Next	200 kWh per month	49,825	0.095280	0.011093	0.106373	4,747	553	5,300
Over	1,000 kWh per month	234,706	0.095280	0.021093	0.116373	22,363	4,951	27,313
Base Revenue		640,060				60,985	26,313	87,298
PPCA Revenue						(1,185)	0	(1,185)
Total Revenue						59,800	26,313	86,113

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate Pur Pwr	Proposed Rate Dist Wires	Proposed Rate Total	Proposed Revenue Pur Pwr	Proposed Revenue Dist Wires	Proposed Revenue Total
1. RESIDENTIAL SERVICE (Continued)							
Res - Gov							
Service Charge (12 Month Sum)	318	0.00	16.50	16.50	0	5,247	5,247
Energy Charge per kWh							
First 200 kWh per month	60,246	0.095280	0.001093	0.096373	5,740	66	5,806
Next 200 kWh per month	44,692	0.095280	0.001093	0.096373	4,258	49	4,307
Next 200 kWh per month	28,446	0.095280	0.011093	0.106373	2,710	316	3,026
Next 200 kWh per month	20,173	0.095280	0.011093	0.106373	1,922	224	2,146
Next 200 kWh per month	15,693	0.095280	0.011093	0.106373	1,495	174	1,669
Over 1,000 kWh per month	49,347	0.095280	0.021093	0.116373	4,702	1,041	5,743
Base Revenue	218,597				20,827	7,117	27,944
PPCA Revenue					(404)	0	(404)
Total Revenue					20,423	7,117	27,540
Base Revenue	364,970,959				34,774,432	10,636,094	45,410,526
PPCA Revenue					(675,197)	0	(675,197)
Total Revenue					34,099,235	10,636,094	44,735,329
2. IRRIGATION SERVICE							
Irrigation Time of Use							
Service Charge (12 Month Sum)	144	0.00	65.00	65.00	0	9,360	9,360
On-Peak Demand	2,234.49	8.90	0.00	8.90	19,887	0	19,887
NCP Demand	8,466.81	0.00	1.63	1.63	0	13,801	13,801
Energy Charge per kWh	1,730,345	0.074061	0.000016	0.074077	128,151	28	128,179
Base Revenue					148,038	23,189	171,227
PPCA Revenue					(3,201)	0	(3,201)
Total Revenue					144,837	23,189	168,026
Irrigation Pumping							
Service Charge (12 Month Sum)	132	0.00	60.00	60.00	0	7,920	7,920
NCP Demand	12,025.74	5.90	1.63	7.53	70,952	19,602	90,554
Energy Charge per kWh	2,572,007	0.074061	0.010016	0.084077	190,485	25,761	216,247
Base Revenue					261,437	53,283	314,721
PPCA Revenue					(4,759)	0	(4,759)
Total Revenue					256,678	53,283	309,962
Base Revenue	4,302,352				409,475	76,472	485,948
PPCA Revenue					(7,960)	0	(7,960)
Total Revenue					401,515	76,472	477,988

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE							
Sm Comm Demand - Net Metering							
Service Charge (12 Month Sum)	5	0.00	35.00	35.00	0	175	175
NCP Demand > 3 kW	73.68	6.31	4.48	10.79	465	330	795
Energy Charge per kWh	24,280	0.074926	0.000581	0.075507	1,819	14	1,833
Base Revenue					2,284	519	2,803
PPCA Revenue					(44)	0	(44)
Total Revenue					2,240	519	2,759
Small Commercial Demand							
Service Charge (12 Month Sum)	5,552	0.00	35.00	35.00	0	194,320	194,320
NCP Demand > 3 kW	187,060.45	6.31	4.48	10.79	1,180,351	838,031	2,018,382
Energy Charge per kWh	63,019,478	0.074926	0.000581	0.075507	4,721,797	36,614	4,758,412
Base Revenue					5,902,148	1,068,965	6,971,114
PPCA Revenue					(116,587)	0	(116,587)
Total Revenue					5,785,561	1,068,965	6,854,527
Small Commercial Energy							
Service Charge (12 Month Sum)	35,164	0.00	21.50	21.50	0	756,026	756,026
Energy Charge per kWh	38,541,431	0.090020	0.015019	0.105039	3,469,500	578,854	4,048,353
Base Revenue					3,469,500	1,334,880	4,804,379
PPCA Revenue					(71,301)	0	(71,301)
Total Revenue					3,398,199	1,334,880	4,733,078
Small Commercial - Net Metering							
Service Charge (12 Month Sum)	49	0.00	30.00	30.00	0	1,470	1,470
Energy Charge per kWh	64,010	0.090020	0.015019	0.105039	5,762	961	6,724
Base Revenue					5,762	2,431	8,194
PPCA Revenue					(118)	0	(118)
Total Revenue					5,644	2,431	8,076
Small Commercial TOU							
Service Charge (12 Month Sum)	91	0.00	40.00	40.00	0	3,640	3,640
On-Peak Demand	1,430.12	15.00	0.00	15.00	21,452	0	21,452
NCP kW	3,175.62	0.00	4.48	4.48	0	14,227	14,227
Energy Charge per kWh	1,020,044	0.047111	0.015145	0.062256	48,055	15,449	63,504
Base Revenue					69,507	33,316	102,823
PPCA Revenue					(1,887)	0	(1,887)
Total Revenue					67,620	33,316	100,936
SC Energy Gov							
Service Charge (12 Month Sum)	3,208	0.00	21.50	21.50	0	68,972	68,972
Energy Charge per kWh	3,559,150	0.090020	0.015019	0.105039	320,395	53,455	373,850
Base Revenue					320,395	122,427	442,822
PPCA Revenue					(6,585)	0	(6,585)
Total Revenue					313,810	122,427	436,237

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE (Continued)							
SC Demand Gov							
Service Charge (12 Month Sum)	784	0.00	35.00	35.00	0	27,440	27,440
NCP Demand > 3 kW	26,495.68	6.31	4.48	10.79	167,188	118,701	285,888
Energy Charge per kWh	7,582,510	0.074926	0.000581	0.075507	568,127	4,405	572,533
Base Revenue					735,315	150,546	885,861
PPCA Revenue					(14,029)	0	(14,029)
Total Revenue					721,286	150,546	871,832
Base Revenue	113,810,903				10,504,911	2,713,084	13,217,996
PPCA Revenue					(210,551)	0	(210,551)
Total Revenue					10,294,360	2,713,084	13,007,445
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE							
Large C&I Secondary							
Service Charge (12 Month Sum)	983	0.00	170.00	170.00	0	167,110	167,110
NCP Demand	189,369.16	7.76	2.99	10.75	1,469,505	566,214	2,035,718
Energy Charge per kWh	76,311,058	0.066123	0.006165	0.072288	5,045,916	470,458	5,516,374
Base Revenue					6,515,421	1,203,782	7,719,202
PPCA Revenue					(141,175)	0	(141,175)
Total Revenue					6,374,246	1,203,782	7,578,027
Large C&I Primary							
Service Charge (12 Month Sum)	36	0.00	170.00	170.00	0	6,120	6,120
NCP Demand	17,172.00	7.76	2.99	10.75	133,255	51,344	184,599
Energy Charge per kWh	8,497,320	0.066123	0.006165	0.072288	561,868	52,386	614,254
Primary Discount on Demand & Energy		-1.00%	-1.00%	-1.00%	(6,951)	(1,037)	(7,989)
Base Revenue					688,172	108,813	796,984
PPCA Revenue					(15,722)	0	(15,722)
Total Revenue					672,450	108,813	781,262

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
Large C&I TOU							
Service Charge (12 Month Sum)	31	0.00	175.00	175.00	0	5,425	5,425
On-Peak Demand	690.80	23.00	0.00	23.00	15,888	0	15,888
NCP kW	5,713.20	0.00	2.99	2.99	0	17,082	17,082
Energy Charge per kWh	564,880	0.047111	0.006165	0.053276	26,612	3,482	30,095
Base Revenue					42,500	25,989	68,490
PPCA Revenue					(1,047)	0	(1,047)
Total Revenue					41,453	25,989	67,443
Large C&I GOV							
Service Charge (12 Month Sum)	362	0.00	170.00	170.00	0	61,540	61,540
NCP Demand	64,343.36	7.76	2.99	10.75	499,304	192,387	691,691
Energy Charge per kWh	17,180,160	0.066123	0.006165	0.072288	1,136,004	105,916	1,241,919
Base Revenue					1,635,308	359,843	1,995,150
PPCA Revenue					(31,784)	0	(31,784)
Total Revenue					1,603,524	359,843	1,963,366
LC&I Trans (Current TOU) *Billed at Subtransmission Delivery Level*							
Service Charge (12 Month Sum)	12	0.00	170.00	170.00	0	2,040	2,040
NCP kW	53,106.00	7.76	2.99	10.75	412,103	158,787	570,890
Energy Charge per kWh	30,204,000	0.066123	0.006165	0.072288	1,997,179	186,208	2,183,387
Subtransmission Discount on Demand & Energy		-7.50%	-7.50%	-7.50%	(180,696)	(25,875)	(206,571)
Base Revenue					2,228,586	321,160	2,549,746
PPCA Revenue					(55,877)	0	(55,877)
Total Revenue					2,172,709	321,160	2,493,869

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

		Billing	Proposed Rate			Proposed Revenue		
		Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)								
LP Substation	***Billed at Substation Delivery Level***							
Service Charge (12 Month Sum)		24	0.00	170.00	170.00	0	4,080	4,080
NCP kW		67,500.00	7.76	2.99	10.75	523,800	201,825	725,625
Energy Charge per kWh		38,802,000	0.066123	0.006165	0.072288	2,565,705	239,214	2,804,919
Substation Discount on Demand & Energy			-5.00%	-5.00%	-5.00%	(154,475)	(22,052)	(176,527)
Base Revenue						2,935,030	423,067	3,358,097
PPCA Revenue						(65,987)	0	(65,987)
Total Revenue						2,869,043	423,067	3,292,110
Base Revenue		171,559,418				14,045,017	2,442,654	16,487,669
PPCA Revenue						(311,592)	0	(311,592)
Total Revenue						13,733,425	2,442,654	16,176,077
5. LIGHTING SERVICE								
175 W MVL	102 kWh per month	6,039	6.37	0.95	7.32	38,468	5,753	44,221
100 W HPS	51 kWh per month	2,594	3.19	5.23	8.42	8,275	13,576	21,851
175 W MVL CO	101 kWh per month	320	6.31	0.50	6.81	2,019	160	2,179
100 W HPS CO	51 kWh per month	3,644	3.19	2.27	5.46	11,624	8,281	19,906
250 W HPS	130 kWh per month	1,211	8.12	5.97	14.09	9,833	7,229	17,062
Base Revenue		13,808				70,219	34,999	105,219
PPCA Revenue						(2,035)	0	(2,035)
Total Revenue						68,184	34,999	103,184
kWh		1,100,103						
6. RESALE REVENUE								
Base Revenue						3,222,980	475,687	3,698,667
PPCA Revenue						0	0	0
Total Revenue		46,862,961				3,222,980	475,687	3,698,667

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
7. TOTAL REVENUE							
Base Revenue	702,606,696				63,027,034	16,378,990	79,406,025
PPCA Revenue					(1,207,335)	0	(1,207,335)
Other Revenue					0	863,547	863,547
Total					61,819,699	17,242,537	79,062,237

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL TIME OF USE RATES - 2010 DATA

			Billing Units	Proposed Rate			Proposed Revenue		
				Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE									
Proposed Residential Rate									
Service Charge (12 Month Sum)			417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First	400	kWh per month	138,330,393	0.095280	0.001093	0.096373	13,180,120	151,195	13,331,315
Next	600	kWh per month	119,935,547	0.095280	0.011093	0.106373	11,427,459	1,330,445	12,757,904
Over	1,000	kWh per month	106,705,019	0.095280	0.021093	0.116373	10,166,854	2,250,729	12,417,583
Total									
Base Revenue			364,970,959				34,774,433	10,623,281	45,397,714
PPCA Revenue							(673,607)	0	(673,607)
Total Revenue							34,100,826	10,623,281	44,724,107

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL TIME OF USE RATES - 2010 DATA

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Time of Use - Including Weekends On-peak							
Service Charge (12 Month Sum)	417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Desired Discount 2.5% Applied to Power Supply							
Calculated Discount on total Energy Charges		**2.30%**					
Estimated On Peak kWh							
First 400 kWh per month	37,349,206	0.202042	0.001093	0.203135	7,546,108	40,823	7,586,931
Next 600 kWh per month	32,382,598	0.202042	0.011093	0.213135	6,542,645	359,220	6,901,865
Over 1,000 kWh per month	28,810,355	0.202042	0.021093	0.223135	5,820,902	607,697	6,428,599
Total	98,542,159						
Estimated Off Peak kWh							
First 400 kWh per month	100,981,187	0.055792	0.001093	0.056885	5,633,942	110,372	5,744,315
Next 600 kWh per month	87,552,949	0.055792	0.011093	0.066885	4,884,754	971,225	5,855,979
Over 1,000 kWh per month	77,894,664	0.055792	0.021093	0.076885	4,345,899	1,643,032	5,988,931
Total	266,428,800						
Base Revenue	364,970,959				34,774,250	12,711,436	47,485,687
PPCA Revenue					(673,607)	0	(673,607)
Total Revenue					34,100,643	12,711,436	46,812,080
Proposed Residential Time of Use - Excluding Weekends On-Peak							
Service Charge (12 Month Sum)	417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Assumed Off Peak kWh % 73%							
Estimated On Peak kWh							
First 400 kWh per month	37,349,206	0.207223	0.001093	0.208316	7,739,615	40,823	7,780,437
Next 600 kWh per month	32,382,598	0.207223	0.011093	0.218316	6,710,419	359,220	7,069,639
Over 1,000 kWh per month	28,810,355	0.207223	0.021093	0.228316	5,970,168	607,697	6,577,865
Total	98,542,159						
Estimated Off Peak kWh							
First 400 kWh per month	100,981,187	0.057223	0.001093	0.058316	5,778,446	110,372	5,888,819
Next 600 kWh per month	87,552,949	0.057223	0.011093	0.068316	5,010,042	971,225	5,981,267
Over 1,000 kWh per month	77,894,664	0.057223	0.021093	0.078316	4,457,366	1,643,032	6,100,399
Total	266,428,800						
Base Revenue	364,970,959				35,666,056	12,711,436	48,377,493
PPCA Revenue					(673,607)	0	(673,607)
Total Revenue					34,992,449	12,711,436	47,703,886

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL DEMAND RATES - 2010 DATA

1. RESIDENTIAL SERVICE

			Billing Units	Proposed Rate			Proposed Revenue		
				Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Rate									
Service Charge (12 Month Sum)			417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First	400	kWh per month	138,330,393	0.095280	0.001093	0.096373	13,180,120	151,195	13,331,315
Next	600	kWh per month	119,935,547	0.095280	0.011093	0.106373	11,427,459	1,330,445	12,757,904
Over	1,000	kWh per month	106,705,019	0.095280	0.021093	0.116373	10,166,854	2,250,729	12,417,583
Total									
Base Revenue			364,970,959				34,774,433	10,623,281	45,397,714
PPCA Revenue							(673,607)	0	(673,607)
Total Revenue							34,100,826	10,623,281	44,724,107

			Billing Units	Proposed Rate			Proposed Revenue		
				Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Demand Rate									
Service Charge (12 Month Sum)			417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Demand Charge	Assumed	3.00	1,252,893	8.00	0.50	8.50	10,023,144	626,447	10,649,591
First	400	kWh per month	138,330,393	0.068402	0.000000	0.068402	9,462,076	0	9,462,076
Next	600	kWh per month	119,935,547	0.068402	0.009065	0.077467	8,203,831	1,087,216	9,291,047
Over	1,000	kWh per month	106,705,019	0.068402	0.019065	0.087467	7,298,837	2,034,331	9,333,168
Total			364,970,959						
Base Revenue							34,987,888	12,727,061	47,714,949
PPCA Revenue							(673,607)	0	(673,607)
Total Revenue							34,314,281	12,727,061	47,041,342

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL DEMAND RATES - 2010 DATA

1. RESIDENTIAL SERVICE

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Rate							
Service Charge (12 Month Sum)	417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First 400 kWh per month	138,330,393	0.095280	0.001093	0.096373	13,180,120	151,195	13,331,315
Next 600 kWh per month	119,935,547	0.095280	0.011093	0.106373	11,427,459	1,330,445	12,757,904
Over 1,000 kWh per month	106,705,019	0.095280	0.021093	0.116373	10,166,854	2,250,729	12,417,583
Total							
Base Revenue	364,970,959				34,774,433	10,623,281	45,397,714
PPCA Revenue					(673,607)	0	(673,607)
Total Revenue					34,100,826	10,623,281	44,724,107

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Demand Rate							
Service Charge (12 Month Sum)	417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Demand Charge Assumed 3.00	1,252,893	8.00	0.50	8.50	10,023,144	626,447	10,649,591
First 400 kWh per month	138,330,393	0.068402	0.000000	0.068402	9,462,076	0	9,462,076
Next 600 kWh per month	119,935,547	0.068402	0.009065	0.077467	8,203,831	1,087,216	9,291,047
Over 1,000 kWh per month	106,705,019	0.068402	0.019065	0.087467	7,298,837	2,034,331	9,333,168
Total	364,970,959						
Base Revenue					34,987,888	12,727,061	47,714,949
PPCA Revenue					(673,607)	0	(673,607)
Total Revenue					34,314,281	12,727,061	47,041,342

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED PPCA BASE COST - 2010 DATA

	Adjusted 2010	Proposed 2010	Difference
Total kWh Sales	655,743,735	655,743,735	0
Less Lighting kWh Sales	1,100,103		(1,100,103)
Jurisdictional kWh Sales	654,643,632	655,743,735	1,100,103
Purchased Power	58,579,697	58,579,697	0
Power Cost per kWh Sold	0.089483	0.089333	(0.000150)
Authorized Base Cost	0.065798	**0.091183**	0.025385
Average PPCA Factor	0.023685	(0.001850)	(0.025535)

Adjusted 2010 Power Cost on Supplemental Schedule F-7.0
Adjusted 2010 kWh Sales on Supplemental Schedule F-2.0
Note: PPCA to be charged on lighting under new rates

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 PURCHASED POWER COST ADJUSTMENT REVENUE UNDER PROPOSED RATES
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

kWh Sales	January	February	March	April	May	June	July	August	September	October	November	December	Total
Residential	25,849,475	21,682,468	19,197,187	18,556,599	20,450,231	29,930,248	47,944,080	56,760,772	51,765,675	30,864,964	19,860,637	21,229,417	364,111,753
Residential - Seasonal	0	0	1	0	0	0	0	548	0	0	0	0	549
Residential - Net Metering	0	398	13,288	16,374	23,004	33,953	77,774	159,445	141,903	79,565	44,468	49,888	640,060
Res - Gov	19,151	14,472	11,791	11,286	12,504	20,481	33,221	36,405	26,581	13,657	8,437	10,611	218,597
Irrigation Time of Use	13,824	32,327	56,968	148,711	210,413	242,921	264,488	304,783	229,249	140,818	800,158	-714,315	1,730,345
Irrigation Pumping	79,943	79,256	140,125	234,689	281,040	379,623	366,338	330,171	288,032	167,864	105,312	119,614	2,572,007
Sm Comm Demand - Net Metering	0	0	0	0	0	0	0	4,440	6,280	5,080	4,000	4,480	24,280
Small Commercial Demand	4,670,602	4,096,814	4,037,334	4,406,968	4,661,116	5,430,165	6,812,189	7,420,720	7,340,476	5,411,838	5,286,189	3,445,267	63,019,478
Small Commercial Energy	2,928,167	2,646,724	2,482,268	2,463,406	2,628,627	3,117,971	4,178,953	4,732,727	4,689,267	3,335,715	2,659,842	2,677,764	38,541,431
Sm Comm Energy - Net Metering	0	0	700	3,945	2,333	3,127	4,845	9,775	7,862	5,168	7,688	18,567	64,010
Small Commercial TOU	50,281	41,363	58,026	72,116	106,411	93,956	110,940	126,121	134,999	78,872	79,438	67,521	1,020,044
SC Energy Gov	343,302	291,556	268,042	263,634	258,209	272,253	322,869	354,676	368,940	277,819	258,290	279,560	3,559,150
SC Demand Gov	577,604	612,313	544,824	563,368	548,389	631,802	739,489	891,794	820,061	632,315	516,218	504,333	7,582,510
Large C&I Secondary	5,944,240	5,356,960	5,089,824	5,296,320	5,704,834	6,221,160	7,781,600	8,424,240	8,319,520	6,595,680	5,841,800	5,734,880	76,311,058
Large C&I Primary	719,760	672,240	649,680	597,600	644,280	633,840	703,560	880,200	858,480	819,000	632,280	686,400	8,497,320
Large C&I TOU	5,280	4,280	11,640	60,360	69,080	63,600	65,440	78,280	82,080	29,040	62,320	53,480	564,880
Large C&I GOV	1,287,200	1,193,440	1,106,320	1,145,080	1,313,320	1,330,160	1,541,760	1,894,520	2,070,000	1,744,440	1,284,280	1,269,640	17,180,160
LC&I Trans (Current TOU)	2,244,000	1,512,000	1,722,000	2,178,000	2,880,000	2,820,000	3,486,000	2,268,000	3,282,000	3,414,000	2,520,000	1,878,000	30,204,000
LC&I Substation (Current Contract)	2,611,200	2,409,600	3,110,400	2,798,400	2,913,600	2,980,800	2,932,800	2,961,600	2,913,600	3,739,200	3,264,000	3,033,600	35,668,800
LC&I Substation (Current LP)	397,200	290,400	254,400	246,000	194,400	210,000	274,800	282,000	270,000	172,800	214,800	326,400	3,133,200
Total Large Coml & Industrial	94,004	92,858	93,045	92,085	92,392	92,455	92,248	92,455	82,475	92,085	91,959	92,042	1,100,103
Resale													0
Total excluding Resale	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Adjusted Test Year Power Cost													
Total kWh	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Less Lighting													0
Jurisdictional kWh Sales	47,835,233	41,029,269	38,847,863	39,154,941	42,994,183	54,508,515	77,733,394	88,013,672	83,677,480	57,619,920	43,562,116	40,767,149	655,743,735
Adjusted PP Excluding TPS	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Remove Substation Contract	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove AES Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remove Other Sales	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remainder Pur Power	4,081,733.78	3,856,936.39	3,965,647.26	4,281,417.19	4,739,223.64	5,611,123.66	6,752,806.18	6,210,200.88	5,489,092.05	4,714,210.37	4,451,056.25	4,426,249.05	58,579,696.70
Pur Pwr per Jurisd kWh Sold	0.085329	0.094005	0.102081	0.109346	0.110229	0.102940	0.086871	0.070560	0.065598	0.081816	0.102177	0.108574	0.089333
Power Cost in Base	4,361,760.05	3,741,171.84	3,542,264.69	3,570,264.99	3,920,338.59	4,970,249.92	7,087,964.07	8,025,350.65	7,629,963.66	5,253,957.17	3,972,124.42	3,717,270.95	59,792,681.00
Authorized Base Cost	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183	0.091183
Power Cost to Collect	(280,026.27)	115,764.55	423,382.57	711,152.20	818,885.05	640,873.74	(335,157.89)	(1,815,149.77)	(2,140,871.61)	(539,746.80)	478,931.83	708,978.10	(1,212,984.30)
Calculated PPCA Factor	(0.005854)	0.002822	0.010898	0.018163	0.019046	0.011757	(0.004312)	(0.020623)	(0.025585)	(0.009367)	0.010994	0.017391	(0.001850)
Average PPCA Factor	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)	(0.001850)

Usage from Sup Schedule F-2.0
Power Cost from Sup Schedule F-7.0
Proposed Factor developed on Sup Schedule N-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 PURCHASED POWER COST ADJUSTMENT REVENUE UNDER PROPOSED RATES
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

Class Revenue	January	February	March	April	May	June	July	August	September	October	November	December	Total
Residential	(47,822)	(40,113)	(35,515)	(34,330)	(37,833)	(55,371)	(88,697)	(105,007)	(95,766)	(57,100)	(36,779)	(39,274)	(673,607)
Residential - Seasonal	0	0	0	0	0	0	0	(1)	0	0	0	0	(1)
Residential - Net Metering	0	(1)	(25)	(30)	(43)	(63)	(144)	(295)	(263)	(147)	(82)	(92)	(1,185)
Res - Gov	(35)	(27)	(22)	(21)	(23)	(38)	(61)	(67)	(49)	(25)	(16)	(20)	(404)
Irrigation Time of Use	(26)	(60)	(105)	(275)	(389)	(449)	(489)	(564)	(424)	(261)	(1,480)	1,321	(3,201)
Irrigation Pumping	(148)	(147)	(259)	(434)	(520)	(702)	(678)	(611)	(533)	(311)	(195)	(221)	(4,759)
Sm Comm Demand - Net Metering	0	0	0	0	0	0	0	(8)	(12)	(9)	(7)	(8)	(44)
Small Commercial Demand	(8,641)	(7,579)	(7,469)	(8,153)	(8,623)	(10,046)	(12,603)	(13,728)	(13,580)	(10,012)	(9,779)	(6,374)	(116,587)
Small Commercial Energy	(5,417)	(4,896)	(4,592)	(4,557)	(4,863)	(5,768)	(7,731)	(8,756)	(8,675)	(6,171)	(4,921)	(4,954)	(71,301)
Sm Comm Energy - Net Metering	0	0	(1)	(7)	(4)	(6)	(9)	(18)	(15)	(10)	(14)	(34)	(118)
Small Commercial TOU	(93)	(77)	(107)	(133)	(197)	(174)	(205)	(233)	(250)	(146)	(147)	(125)	(1,887)
SC Energy Gov	(635)	(539)	(496)	(488)	(478)	(504)	(597)	(656)	(683)	(514)	(478)	(517)	(6,585)
SC Demand Gov	(1,069)	(1,133)	(1,008)	(1,042)	(1,015)	(1,169)	(1,368)	(1,650)	(1,517)	(1,170)	(955)	(933)	(14,029)
Large C&I Secondary	(10,997)	(9,910)	(9,416)	(9,798)	(10,554)	(11,509)	(14,396)	(15,585)	(15,391)	(12,202)	(10,807)	(10,610)	(141,175)
Large C&I Primary	(1,332)	(1,244)	(1,202)	(1,106)	(1,192)	(1,173)	(1,302)	(1,628)	(1,588)	(1,515)	(1,170)	(1,270)	(15,722)
Large C&I TOU	(10)	(8)	(22)	(112)	(128)	(118)	(121)	(145)	(115)	(54)	(115)	(99)	(1,047)
Large C&I GOV	(2,381)	(2,208)	(2,047)	(2,118)	(2,430)	(2,461)	(2,852)	(3,505)	(3,830)	(3,227)	(2,376)	(2,349)	(31,784)
LC&I Trans (Current TOU)	(4,151)	(2,797)	(3,186)	(4,029)	(5,328)	(5,217)	(6,449)	(4,196)	(6,072)	(6,316)	(4,662)	(3,474)	(55,877)
LC&I Substation (Current Contract)	(4,831)	(4,458)	(5,754)	(5,177)	(5,390)	(5,514)	(5,426)	(5,479)	(5,390)	(6,918)	(6,038)	(5,612)	(65,987)
LC&I Substation (Current LP)	(735)	(537)	(471)	(455)	(360)	(389)	(508)	(522)	(500)	(320)	(397)	(604)	(5,798)
Total Large Coml & Industrial	(174)	(172)	(172)	(170)	(171)	(171)	(171)	(171)	(153)	(170)	(170)	(170)	(2,035)
Resale													0
Total	(88,497)	(75,906)	(71,869)	(72,435)	(79,541)	(100,842)	(143,807)	(162,825)	(154,806)	(106,598)	(80,588)	(75,419)	(1,213,133)

Usage from Sup Schedule F-2.0
Power Cost from Sup Schedule F-7.0
Proposed Factor developed on Sup Schedule N-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED PROPERTY TAX ADJUSTMENT

	Adjusted Test Year	2010
Total kWh Sales	655,743,735	655,743,735
Less Lighting kWh Sales	1,100,103	
Jurisdictional kWh Sales	654,643,632	655,743,735
Actual Property Tax	1,001,834.20	**1,005,148.00**
Base Property Tax	1,001,834.20	1,001,834.20
Difference	0.00	3,313.80
Minimum Amount Collected		25,000.00
Amount to Collect	0.00	0.00
PTA Factor		$ -

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED OTHER REVENUE

			Actual 2010		Adjusted 2010		Proposed 2010		Change	
		Quantity	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue
451.00	Reconnect Fees	2,790	$ 25.00	$ 69,750.00	$ 25.00	$ 69,750.00	$ 40.00	$ 111,600.00	$ 15.00	$ 41,850.00
451.00	Connect Fees	11,236	$ 25.00	280,900.00	$ 25.00	280,900.00	$ 40.00	$ 449,440.00	$ 15.00	168,540.00
454.00	Pole Attachment Rental **	10,615	$ 20.99	222,768.04	$ 21.21	225,144.15	$ 21.21	$ 225,144.15	$ -	0.00
456.10	Returned Check Collection Charges	804	$ 15.00	12,060.00	$ 15.00	12,060.00	$ 25.00	$ 20,100.00	$ 10.00	8,040.00
456.20	Meter Re-Read Charge	29	$ 5.00	145.00	$ 5.00	145.00	$ 25.00	$ 725.00	$ 20.00	580.00
456.30	Meter Test Fees	0	$ 25.00	0.00	$ 25.00	0.00	$ 40.00	$ -	$ 15.00	0.00
	Theft of Service			9,052.12		9,052.12				9,052.12
	Sales Tax on Other Revenue			9,883.17		9,883.17				9,883.17
	Power Displacement Agreement *			117,546.00						
	Device Rental Agreement *			12,000.00						
	Disbursement Management Agm't *			15,000.00						
	Adjustment			(35.00)		(35.00)				(35.00)
	Late Fees	3,769,168	0.0%	0.00	0.0%	0.00	1.5%	$ 56,537.52	1.5%	56,537.52
	Total			$ 749,069.33		$ 606,899.44		$ 863,546.67		$ 294,447.81

See also Supplemental Schedule C-4.0
**** Provided by Contract - will not continue in 2011 and beyond***
***** Contract changed April 2010***

SUPPLEMENTAL SCHEDULES O – Q
INTENTIONALLY LEFT BLANK

Supplemental Sections O through Q

Intentionally Left Blank

SUPPLEMENTAL SCHEDULE R

Supplemental Section R

Individual Demand Data

MOHAVE ELECTRIC COOPERATIVE

IRRIGATION TIME OF USE ACCOUNTS (RATE 406)
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

MONTHLY NCP KW WHERE AVAILABLE

Account	Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
24258013	406	100.00	99.60	100.00	99.60	99.60	99.60	99.60	99.20	99.60		48.00		944.80
24258015	406	-	65.31	64.32	64.97	64.91	9.26	7.48	7.19	77.66				361.10
24258017	406	64.00	62.40	64.40	62.40	62.00	70.80	66.00	67.20	64.40				583.60
24258022	406	-	73.69	73.02	72.83	88.62	10.48	9.07	8.45	10.41		14.40		360.97
24258030	406	-	75.20	75.20	75.20	75.20	75.20	73.60	73.60	75.20		72.00	73.60	744.00
24258031	406	-	76.00	76.00	76.00	75.60	75.60	74.80	75.20	75.60		75.20	75.20	755.20
119150018	406	7.20	6.40	84.00	86.40	87.20	89.60	88.00	89.60	89.60		6.40	6.40	640.80
119150020	406	-	-	84.40	82.40	80.40	75.60	78.40	73.60	44.80				519.60
119150021	406	-	-	64.80	62.40	60.00	57.60	57.60	56.80	64.80		64.00	-	488.00
130958009	406	-	-	-	-	172.80	168.00	167.20	168.00					676.00
132866007	406	34.53	23.61	3.22	0.31	0.37	0.33	0.30	0.33			0.30	48.67	111.97
132866008	406	22.14	0.06	49.06	50.08	12.16	49.08	49.16	49.57			50.24	2.46	334.01
Total		227.87	482.27	738.42	732.59	878.86	781.15	771.21	768.74	602.07	-	330.54	206.33	6,520.05

PROJECTED MONTHLY NCP KW

Account	Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
24258013	406	100.00	99.60	100.00	99.60	99.60	99.60	99.60	99.20	**99.60**	**100.00**	**48.00**	**100.00**	1,144.80
24258015	406	-	65.31	64.32	64.97	64.91	9.26	7.48	7.19	**77.66**	**77.66**	**77.66**	**-**	516.42
24258017	406	64.00	62.40	64.40	62.40	62.00	70.80	66.00	67.20	**64.40**	**70.80**	**70.80**	**70.80**	796.00
24258022	406	-	73.69	73.02	72.83	88.62	10.48	9.07	8.45	**10.41**	**-**	**14.40**	**88.62**	449.59
24258030	406	-	75.20	75.20	75.20	75.20	75.20	73.60	73.60	**75.20**	**75.20**	**72.00**	**73.60**	819.20
24258031	406	-	76.00	76.00	76.00	75.60	75.60	74.80	75.20	**75.60**	**76.00**	**75.20**	**75.20**	831.20
119150018	406	7.20	6.40	84.00	86.40	87.20	89.60	88.00	89.60	**89.60**	**89.60**	**6.40**	**6.40**	730.40
119150020	406	-	-	84.40	82.40	80.40	75.60	78.40	73.60	**44.80**	**84.40**	**84.40**	**84.40**	772.80
119150021	406	-	-	64.80	62.40	60.00	57.60	57.60	56.80	**64.80**	**-**	**-**	**-**	424.00
130958009	406	-	-	-	-	172.80	168.00	167.20	168.00	**172.80**	**172.80**	**172.80**	**172.80**	1,367.20
132866007	406	34.53	23.61	3.22	0.31	0.37	0.33	0.30	0.33	**34.53**	**34.53**	**0.30**	**48.67**	181.03
132866008	406	22.14	0.06	49.06	50.08	12.16	49.08	49.16	49.57	**50.08**	**50.08**	**50.24**	**2.46**	434.17
Total		227.87	482.27	738.42	732.59	878.86	781.15	771.21	768.74	859.48	831.07	672.20	722.95	8,466.81

MOHAVE ELECTRIC COOPERATIVE

IRRIGATION TIME OF USE ACCOUNTS (RATE 406)
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

Account	Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
		MONTHLY BILLING KW												
24258013	406	-	-	-	-	-	-	-	-	-	-	-	-	-
24258015	406	-	-	-	-	-	64.74	7.52	6.88	-	-	0.10	-	79.24
24258017	406	-	-	-	-	-	-	-	-	-	-	-	-	-
24258022	406	-	-	-	-	73.35	67.69	8.65	-	-	-	5.77	-	155.46
24258030	406	-	-	-	-	-	-	-	-	-	-	-	-	-
24258031	406	-	-	-	-	-	-	-	-	-	-	-	-	-
119150018	406	7.20	95.20	84.80	85.60	3.20	14.40	8.00	6.40	5.60	4.80	6.40	-	321.60
119150020	406	-	-	-	9.20	-	-	-	-	-	-	-	-	9.20
119150021	406	-	-	-	-	-	-	-	-	-	-	-	-	-
130958009	406	-	-	-	172.80	174.40	114.40	166.40	-	166.40	165.60	-	-	960.00
132866007	406	35.42	37.26	0.33	0.46	0.43	0.33	0.31	0.30	0.31	0.66	-	44.24	120.05
132866008	406	44.54	0.06	49.50	50.27	48.93	48.70	48.26	49.39	50.75	100.54	49.00	49.00	588.94
Total		87.16	132.52	134.63	318.33	300.31	310.26	239.14	62.97	223.06	271.60	61.27	93.24	2,234.49

Account	Rate	MONTHLY KWH												
24258013	406	7,280	600	7,960	10,520	17,560	17,800	15,880	22,560	10,240	3,960	8,560	7,280	130,200
24258015	406	-	10,572	1,220	20,978	23,091	24,230	37,612	34,856	21,109	9,156	4,932	-	187,756
24258017	406	4,640	400	5,040	6,680	10,960	11,480	10,520	14,880	6,640	2,720	3,000	7,520	84,480
24258022	406	-	12,018	1,398	23,686	25,373	25,500	38,077	36,827	21,426	-	17,820	8,788	210,913
24258030	406	-	3,040	4,160	4,480	9,280	10,240	12,800	12,800	14,680	4,960	5,600	5,120	87,160
24258031	406	-	3,120	4,240	4,480	9,440	10,400	12,960	13,040	14,360	5,000	5,800	5,240	88,080
119150018	406	1,040	1,760	16,720	37,120	30,960	43,120	39,360	43,520	39,200	5,280	1,440	1,600	261,120
119150020	406	-	80	7,400	6,320	12,400	13,480	12,520	12,400	3,440	2,880	2,880	40	73,840
119150021	406	-	-	8,000	27,520	19,920	28,240	26,480	25,200	21,440	-	-	-	156,800
130958009	406	320	160	320	4,800	51,200	53,280	55,760	82,400	73,600	90,160	720	240	412,960
132866007	406	418	537	204	182	165	197	167	173	154	157	166	1,530	4,050
132866008	406	126	40	306	1,945	64	4,954	2,352	6,127	3,560	2,600	1,600	567	24,241
Total		13,824	32,327	56,968	148,711	210,413	242,921	264,488	304,783	229,849	126,873	52,518	37,925	1,721,600

Mohave Electric Cooperative, Inc.
Irrigation Pumping (Rate 407)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	4	6	10	11	10	11	11	11	10	7	6	7	104
Metered kW	695.29	821.62	1,088.18	1,159.05	1,056.34	1,213.03	1,235.42	1,221.15	1,124.00	914.89	786.82	709.95	12,025.74
Load Factor - %	15.45	14.35	17.31	28.12	35.76	43.47	39.86	36.34	35.59	24.66	18.59	22.65	29.18
Energy kWh	79,943	79,256	140,125	234,689	281,040	379,623	366,338	330,171	288,032	167,864	105,312	119,614	2,572,007
Base	9,503.72	10,348.19	15,744.51	21,725.30	23,694.70	30,509.36	29,895.55	27,697.97	24,573.86	16,140.33	11,615.83	10,993.94	232,443.26
Energy	4,636.69	4,596.85	8,127.25	13,611.95	16,300.32	22,018.15	21,247.61	19,149.92	16,705.86	9,736.10	6,108.09	6,937.62	149,176.41
PCA	2,358.32	2,338.05	4,133.69	5,749.89	6,885.48	9,300.77	8,975.29	8,089.20	7,056.79	3,273.35	2,053.59	2,332.48	62,546.90
Total Revenue	16,498.73	17,283.09	28,005.45	41,087.14	46,880.50	61,828.28	60,118.45	54,937.09	48,336.51	29,149.78	19,777.51	20,264.04	444,166.57

Active Status based on kWh or Revenue.

Mohave Electric Cooperative, Inc.
Small Commercial Demand - Net Metering (502)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	0	0	0	0	0	0	0	1	1	1	1	1	5
Metered kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.60	23.60	20.08	0.00	18.40	85.68
Load Factor - %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.49	36.96	34.00	0.00	32.73	45.98
Billing kW (Calc)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.60	23.60	20.08	0.00	18.40	85.68
Load Factor - %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.49	36.96	34.00	0.00	32.73	45.98
Energy kWh	0	0	0	0	0	0	0	9,040	6,280	5,080	4,000	4,480	28,880
Base	0.00	0.00	0.00	0.00	0.00	0.00	0.00	825.70	507.44	413.91	0.00	367.81	2,114.86
Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	485.80	337.49	273.00	214.96	240.76	1,552.01
PCA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	221.48	153.86	124.46	78.00	87.36	665.16
Total Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,532.98	998.79	811.37	292.96	695.93	4,332.03

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Supplemental Schedule R-3.0

Mohave Electric Cooperative, Inc.
Small Commercial Demand (503)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	477	468	463	460	457	450	447	447	446	448	452	448	5,463
Metered kW	14,670.64	14,504.00	14,349.61	15,065.93	16,291.53	17,923.81	19,681.71	20,413.94	19,948.64	18,694.13	16,548.61	15,074.47	203,167.02
Load Factor - %	43.07	44.04	37.85	42.48	41.17	45.42	47.50	51.91	51.05	39.22	37.63	38.40	43.59
Billing kW (Calc)	14,670.64	14,504.00	14,349.61	15,065.93	16,291.53	17,923.81	19,681.71	20,413.94	19,948.64	18,694.13	16,548.61	15,074.47	203,167.02
Load Factor - %	43.07	44.04	37.85	42.48	41.17	45.42	47.50	51.91	51.05	39.22	37.63	38.40	43.59
Energy kWh	4,700,911	4,292,697	4,040,654	4,607,788	4,989,919	5,861,485	6,956,069	7,883,911	7,332,476	5,455,323	4,483,396	4,307,052	64,911,681
Base	363,162.27	350,392.47	323,900.72	376,067.54	402,877.59	458,222.46	530,021.72	600,476.19	549,409.51	437,060.86	369,098.81	262,775.08	5,023,465.22
Energy	251,857.38	230,010.40	217,144.78	244,897.02	267,171.22	314,996.36	373,819.16	423,273.09	395,476.73	292,490.76	242,337.69	145,509.09	3,398,983.68
PCA	138,254.60	126,261.73	119,199.29	124,817.70	121,922.93	143,606.41	170,423.70	192,969.65	180,297.38	119,567.35	87,894.63	52,715.35	1,577,930.72
Total Revenue	753,274.25	706,664.60	660,244.79	745,782.26	791,971.74	916,825.23	1,074,264.58	1,216,718.93	1,125,183.62	849,118.97	699,331.13	460,999.52	10,000,379.62

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Mohave Electric Cooperative, Inc.
Small Commercial TOU (506)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	4	7	8	8	8	8	8	8	8	8	8	8	91
Metered kW	53.96	103.26	97.69	120.87	106.64	102.90	105.48	86.78	137.95	239.70	177.07	97.82	1,430.12
Load Factor - %	125.24	59.61	79.84	82.87	134.12	126.82	141.37	195.34	135.92	44.23	62.31	92.90	97.32
Billing kW (Calc)	53.96	103.26	97.69	120.87	106.64	102.90	105.48	86.78	137.95	239.70	177.07	97.82	1,430.12
Load Factor - %	125.24	59.61	79.84	82.87	134.12	126.82	141.37	195.34	135.92	44.23	62.31	92.90	97.32
Energy kWh	50,281	41,363	58,026	72,116	106,411	93,956	110,940	126,121	134,999	78,872	79,438	67,612	1,020,135
Base	3,208.67	3,375.46	4,145.64	5,145.55	5,922.60	5,363.37	6,909.90	7,441.28	17,056.68	13,942.80	10,353.10	1,715.36	84,580.41
Energy	2,534.16	2,084.69	2,924.50	3,634.64	5,363.12	4,735.38	5,591.38	6,356.50	13,607.88	7,950.28	7,251.32	4,558.82	66,592.67
PCA	1,483.29	1,220.21	1,711.77	2,108.20	2,607.08	2,301.93	2,718.03	3,089.96	6,614.96	3,076.00	2,805.60	1,763.80	31,500.83
Total Revenue	7,226.12	6,680.36	8,781.91	10,888.39	13,892.80	12,400.68	15,219.31	16,887.74	37,279.52	24,969.08	20,410.02	8,037.98	182,673.91

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

MOHAVE ELECTRIC COOPERATIVE

SMALL COMMERCIAL TIME OF USE (RATE 506) - DEVELOPMENT OF NCP DEMAND
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

ACCOUNT	RATE	January	February	March	April	May	June	July	August	September	October	November	December	Total
NCP DEMAND - AVAILABLE DATA														
75331001	506	42.52	42.55	42.55	42.66	43.01	43.02	43.12	88.20					387.63
75331004	506	27.97	27.97	27.90	27.87	27.89	27.79	27.94	27.92					223.25
75331005	506	22.97	22.99	22.95	42.40	42.68	42.69	42.62	42.55					281.85
2371018	506	53.26	53.28	53.25	53.36	53.18	53.17	53.04	53.07					425.61
75331000	506			27.05	26.49	26.47	26.53	26.46	26.57					159.57
67575011	506				65.99	69.49	67.73	67.52	70.33					341.06
75331002	506			26.24	21.98	21.95	21.80	21.76	21.71					135.44
75331008	506			25.51	0.10	0.10	0.19	22.21	0.10					48.21
TOTAL		146.72	146.79	225.45	280.85	284.77	282.92	304.67	330.45	0.00	0.00	0.00	0.00	2,002.62
NCP DEMAND - PROJECTED														
75331001	506	42.52	42.55	42.55	42.66	43.01	43.02	43.12	88.20	**88.20**	**42.66**	**42.66**	**42.66**	603.81
75331004	506	27.97	27.97	27.90	27.87	27.89	27.79	27.94	27.92	**27.92**	**27.87**	**27.87**	**27.87**	334.78
75331005	506	22.97	22.99	22.95	42.40	42.68	42.69	42.62	42.55	**42.55**	**42.40**	**42.40**	**42.40**	451.60
2371018	506	53.26	53.28	53.25	53.36	53.18	53.17	53.04	53.07	**53.07**	**53.36**	**53.36**	**53.36**	638.76
75331000	506	0.00	0.00	27.05	26.49	26.47	26.53	26.46	26.57	**26.57**	**26.49**	**26.49**	**26.49**	265.61
67575011	506	0.00	0.00	0.00	65.99	69.49	67.73	67.52	70.33	**70.33**	**65.99**	**65.99**	**65.99**	609.36
75331002	506	0.00	0.00	26.24	21.98	21.95	21.80	21.76	21.71	**21.71**	**21.98**	**21.98**	**21.98**	223.09
75331008	506	0.00	0.00	25.51	0.10	0.10	0.19	22.21	0.10	**0.10**	**0.10**	**0.10**	**0.10**	48.61
TOTAL		146.72	146.79	225.45	280.85	284.77	282.92	304.67	330.45	330.45	280.85	280.85	280.85	3,175.62

MOHAVE ELECTRIC COOPERATIVE

SMALL COMMERCIAL TIME OF USE (RATE 506) - DEVELOPMENT OF NCP DEMAND
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

ACCOUNT	RATE	January	February	March	April	May	June	July	August	September	October	November	December	Total
KWH SALES														
75331001	506	14,275	10,417	10,397	12,033	16,355	14,966	20,454	18,977	23,925	13,260	12,508	11,949	179,516
75331004	506	15,948	12,261	11,956	12,456	15,348	13,061	13,489	16,452	18,828	12,432	12,651	12,959	167,841
75331005	506	7,111	4,966	5,131	7,778	11,115	10,853	12,772	17,463	18,806	8,737	10,082	7,666	122,480
2371018	506	12,947	2,725	3,102	3,841	16,439	10,102	17,804	19,312	7,719	3,667	7,500	104	105,262
75331000	506	-	5,881	9,007	11,825	14,560	12,699	12,797	15,602	17,829	11,038	11,786	12,453	135,477
67575011	506	-	-	9,562	14,414	20,563	21,874	23,081	25,549	33,306	19,908	15,145	12,468	195,870
75331002	506	-	1,561	7,402	9,712	11,959	10,362	10,453	12,695	14,503	9,775	9,708	9,954	108,084
75331008	506	-	3,552	1,469	57	72	39	90	71	83	55	58	59	5,605
TOTAL		50,281	41,363	58,026	72,116	106,411	93,956	110,940	126,121	134,999	78,872	79,438	67,612	1,020,135

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Mohave Electric Cooperative, Inc.
Small Commercial Demand Govt (509)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	65	66	66	66	66	66	66	66	66	65	66	62	786
Metered kW	2,269.49	2,253.33	2,081.55	2,224.33	2,239.82	2,463.16	2,527.09	2,908.12	2,854.33	2,611.36	2,271.82	2,141.88	28,846.28
Load Factor - %	34.21	40.44	35.18	35.18	32.91	35.63	39.33	41.22	40.97	32.55	42.89	31.65	36.84
Billing kW (Calc)	2,269.49	2,253.33	2,081.55	2,224.33	2,239.82	2,463.16	2,527.09	2,908.12	2,854.33	2,611.36	2,271.82	2,141.88	28,846.28
Load Factor - %	34.21	40.44	35.18	35.18	32.91	35.63	39.33	41.22	40.97	32.55	42.89	31.65	36.84
Energy kWh	577,604	612,313	544,824	563,368	548,389	631,802	739,489	891,794	841,901	632,316	701,578	504,333	7,789,710
Base	48,155.01	49,862.17	44,818.15	46,992.64	46,315.47	52,640.64	58,955.13	70,283.51	72,017.39	53,909.97	58,833.30	43,238.90	646,022.28
Energy	31,040.45	32,905.67	29,278.85	30,275.39	29,470.43	33,953.04	39,740.12	47,925.02	47,404.89	33,980.64	37,782.93	27,102.89	420,860.32
PCA	17,039.31	18,063.23	16,072.32	15,068.38	13,435.55	15,479.15	18,117.49	21,848.95	21,491.91	13,740.97	13,704.17	9,834.49	193,895.92
Total Revenue	96,234.77	100,831.07	90,169.32	92,336.41	89,221.45	102,072.83	116,812.74	140,057.48	140,914.19	101,631.58	110,320.40	80,176.28	1,260,778.52

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Supplemental Schedule R-6.0

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Mohave Electric Cooperative, Inc.
Large Power - Secondary (605)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	81	83	82	81	81	81	82	82	82	82	82	83	982
Metered kW	14,114.20	13,621.00	13,552.06	13,572.45	14,649.49	16,298.24	17,849.04	18,492.00	18,008.80	17,656.60	15,940.68	15,614.60	189,369.16
Load Factor - %	56.49	59.97	50.48	54.20	52.88	53.46	61.46	61.23	64.16	50.21	50.90	49.37	55.42
Billing kW (Calc)	14,114.20	13,621.00	13,552.06	13,572.45	14,649.49	16,298.24	17,849.04	18,492.00	18,008.80	17,656.60	15,940.68	15,614.60	189,369.16
Load Factor - %	56.49	59.97	50.48	54.20	52.88	53.46	61.46	61.23	64.16	50.21	50.90	49.37	55.42
Energy kWh	5,932,240	5,489,120	5,089,824	5,296,320	5,763,714	6,272,840	8,161,120	8,424,240	8,319,520	6,595,680	5,841,800	5,734,880	76,921,298
Base	408,004.93	396,368.03	364,126.79	373,737.66	404,829.52	444,823.90	576,226.62	564,273.88	554,789.55	472,782.98	421,690.82	415,820.05	5,397,474.73
Energy	270,391.48	250,194.08	231,994.20	241,406.27	261,455.67	285,916.06	388,013.40	383,976.88	379,203.75	300,631.13	266,269.19	262,267.30	3,521,719.41
PCA	175,001.08	161,929.04	150,149.81	146,619.24	140,536.75	153,684.58	208,563.60	206,393.88	203,828.24	146,621.36	113,915.10	112,203.00	1,919,445.68
Total Revenue	853,397.49	808,491.15	746,270.80	761,763.17	806,821.94	884,424.54	1,172,803.62	1,154,644.64	1,137,821.54	920,035.47	801,875.11	790,290.35	10,838,639.82

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Supplemental Schedule R-7.0

Mohave Electric Cooperative, Inc.
Large Power - Primary (605)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	3	3	3	3	3	3	3	3	3	3	3	3	36
Metered kW	1,324.80	1,290.00	1,296.00	1,340.40	1,376.40	1,352.40	1,449.60	1,518.00	1,587.60	1,636.80	1,539.60	1,460.40	17,172.00
Load Factor - %	73.02	77.55	67.38	61.92	62.92	65.09	65.23	77.94	75.10	67.25	57.04	63.17	67.51
Billing kW (Calc)	1,324.80	1,290.00	1,296.00	1,340.40	1,376.40	1,352.40	1,449.60	1,518.00	1,587.60	1,636.80	1,539.60	1,460.40	17,172.00
Load Factor - %	73.02	77.55	67.38	61.92	62.92	65.09	65.23	77.94	75.10	67.25	57.04	63.17	67.51
Energy kWh	719,760	672,240	649,680	597,600	644,280	633,840	703,560	880,200	858,480	819,000	632,280	686,400	8,497,320
Base	45,723.46	43,218.20	42,248.41	40,307.50	42,786.18	42,076.34	46,201.87	54,920.01	54,608.61	53,288.83	43,830.42	45,525.00	554,734.83
Energy	32,806.66	30,640.70	29,612.41	27,238.60	29,366.28	28,890.44	32,068.27	40,119.51	39,129.51	37,330.03	28,819.32	31,286.10	387,307.83
PCA	21,232.92	19,831.08	19,165.56	16,840.80	15,784.86	15,529.08	17,237.22	21,564.90	21,032.76	19,395.90	12,329.46	13,384.80	213,329.34
Total Revenue	99,763.04	93,689.98	91,026.38	84,386.90	87,937.32	86,495.86	95,507.36	116,604.42	114,770.88	110,014.76	84,979.20	90,195.90	1,155,372.00

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Mohave Electric Cooperative, Inc.
Large Power TOU (606)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	1	1	1	3	3	3	3	3	3	2	3	3	29
Metered kW	0.00	0.00	0.00	57.20	0.80	0.80	100.00	109.60	200.00	108.40 201.2	8.00	7.20	592.00
Load Factor - %	0.00	0.00	0.00	146.56	11,606.18	11,041.67	87.96	96.00	43.11	~~36.01~~	1,081.94	998.36	130.18
Billing kW (Calc)	0.00	0.00	0.00	57.20	0.80	0.80	100.00	109.60	200.00	108.40	8.00	7.20	592.00
Load Factor - %	0.00	0.00	0.00	146.56	11,606.18	11,041.67	87.96	96.00	43.11	36.01	1,081.94	998.36	130.18
Energy kWh	5,280	4,280	11,640	60,360	69,080	63,600	65,440	78,280	62,080	29,040	62,320	53,480	564,880
Base	0.00	0.00	0.00	8,120.08	-3,365.00	880.00	3,196.64	4,689.08	10,490.56	7,975.68	5,191.76	1,572.00	38,750.80
Energy	216.48	175.48	477.24	2,474.76	2,832.28	2,607.60	2,683.04	3,209.48	5,090.56	2,381.28	5,110.24	4,250.88	31,509.32
PCA	155.76	126.26	343.38	1,701.22	1,692.46	1,558.20	1,603.28	1,917.86	3,041.92	1,132.56	2,430.48	2,085.72	17,789.10
Total Revenue	372.24	301.74	820.62	12,296.06	1,159.74	5,045.80	7,482.96	9,816.42	18,623.04	11,489.52	12,732.48	7,908.60	88,049.22

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Supplemental Schedule R-9.0

MOHAVE ELECTRIC COOPERATIVE

LARGE COMMERCIAL TIME OF USE (RATE 606) - DEVELOPMENT OF NCP DEMAND
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

ACCOUNT	RATE	January	February	March	April	May	June	July	August	September	October	November	December	Total
NCP DEMAND - AVAILABLE DATA														
91059001	606	99.20	99.20	99.20	99.60	99.20	99.60	99.20	99.60			99.20		894.00
68912022	606				102.40	110.40	112.80	112.80	112.00					550.40
114504004	606				415.20	396.00	411.60	402.00	412.80					2,037.60
TOTAL		99.20	99.20	99.20	617.20	605.60	624.00	614.00	624.40	0.00	0.00	99.20	0.00	3,482.00
NCP DEMAND - PROJECTED														
91059001	606	99.20	99.20	99.20	99.60	99.20	99.60	99.20	99.60	**99.60**	**99.20**	**99.20**	**99.20**	1,192.00
68912022	606	0.00	0.00	0.00	102.40	110.40	112.80	112.80	112.00	**112.80**		**110.40**	**110.40**	884.00
114504004	606	0.00	0.00	0.00	415.20	396.00	411.60	402.00	412.80	**411.60**	**396.00**	**396.00**	**396.00**	3,637.20
TOTAL		99.20	99.20	99.20	617.20	605.60	624.00	614.00	624.40	624.00	495.20	605.60	605.60	5,713.20
KWH SALES														
91059001	606	5,280	4,280	11,640	15,880	16,680	21,160	21,520	23,120	17,760	12,240	1,640	19,400	170,600
68912022	606	-	-	-	27,920	23,120	21,200	23,520	28,880	32,320	-	40,160	17,280	214,400
114504004	606	-	-	-	16,560	29,280	21,240	20,400	26,280	12,000	16,800	20,520	16,800	179,880
TOTAL		5,280	4,280	11,640	60,360	69,080	63,600	65,440	78,280	62,080	29,040	62,320	53,480	564,880

Mohave Electric Cooperative, Inc.
Large Power Govt (609)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	29	29	29	29	29	29	29	30	31	31	31	31	357
Metered kW	4,481.60	4,347.20	4,146.00	4,588.00	5,093.60	5,048.40	4,846.00	5,685.00	7,364.72	6,802.44	6,059.68	5,880.72	64,343.36
Load Factor - %	38.60	40.85	35.87	34.66	34.66	36.59	42.76	44.53	42.15	34.47	29.44	29.02	36.75
Billing kW (Calc)	4,481.60	4,347.20	4,146.00	4,588.00	5,093.60	5,048.40	4,846.00	5,685.00	7,364.72	6,802.44	6,059.68	5,880.72	64,343.36
Load Factor - %	38.60	40.85	35.87	34.66	34.66	36.59	42.76	44.53	42.15	34.47	29.44	29.02	36.75
Energy kWh	1,287,200	1,193,440	1,106,320	1,145,080	1,313,320	1,330,160	1,541,760	1,883,320	2,234,800	1,744,440	1,284,280	1,269,640	17,333,760
Base	102,366.18	96,782.20	90,849.56	96,925.73	109,523.72	109,850.58	117,521.95	142,580.86	187,662.63	162,073.87	117,619.37	115,207.21	1,448,963.86
Energy	58,670.58	54,397.00	50,426.06	52,192.73	59,861.12	60,628.68	70,273.45	85,841.71	106,217.76	89,256.58	58,537.49	57,870.19	804,173.35
PCA	37,972.40	35,206.48	32,636.44	32,282.66	32,176.34	32,588.92	37,773.12	46,141.34	57,093.82	45,737.88	25,043.46	24,757.98	439,410.84
Total Revenue	199,009.16	186,385.68	173,912.06	181,401.12	201,561.18	203,068.18	225,568.52	274,563.91	350,974.21	297,068.33	201,200.32	197,835.38	2,692,548.05

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Mohave Electric Cooperative, Inc.
LP - Substation (612 and 615)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	2	2	2	2	2	2	2	2	2	2	2	2	24
Metered kW	2,644.80	4,500.00	5,157.60	3,352.80	3,645.60	4,233.60	4,466.40	3,777.60	4,065.60	3,364.80	3,134.40	3,230.40	45,573.60
Load Factor - %	152.89	89.29	87.69	126.11	114.59	104.68	96.53	115.41	232.89	1,086.77	154.15	139.80	196.76
Billing kW (Calc)	2,644.80	4,500.00	5,157.60	3,352.80	3,645.60	4,233.60	4,466.40	3,777.60	4,065.60	3,364.80	3,134.40	3,230.40	45,573.60
Load Factor - %	152.89	89.29	87.69	126.11	114.59	104.68	96.53	115.41	232.89	1,086.77	154.15	139.80	196.76
Energy kWh	3,008,400	2,700,000	3,364,800	3,044,400	3,108,000	3,190,800	3,207,600	3,243,600	6,817,200	27,206,400	3,478,800	3,360,000	65,730,000
Base	116,020.68	136,026.41	161,395.07	125,681.85	131,540.47	142,933.51	148,103.81	138,457.80	221,895.43	568,851.66	131,522.28	132,197.43	2,154,626.40
Energy	78,710.33	69,163.25	83,787.93	76,163.54	76,485.41	78,756.17	80,595.67	81,592.30	164,267.12	355,023.50	85,548.02	85,287.17	1,315,380.41
PCA	88,747.80	79,650.00	99,261.60	74,587.80	76,146.00	78,174.60	78,586.20	79,468.20	167,021.40	302,227.20	67,836.60	65,520.00	1,257,227.40
Total Revenue	283,478.81	284,839.66	344,444.60	276,433.19	284,171.88	299,864.28	307,285.68	299,518.30	553,183.95	1,226,102.36	284,906.90	283,004.60	4,727,234.21

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

Supplemental Schedule R-11.0

Mohave Electric Cooperative, Inc.
LP - Transmission Level (611)

Customer	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Total
Customers	1	1	1	1	1	1	1	1	1	1	1	1	12
Metered kW	4,728.00	3,060.00	2,358.00	3,294.00	4,722.00	4,722.00	4,752.00	4,674.00	4,710.00	4,704.00	3,372.00	3,246.00	48,342.00
Load Factor - %	63.79	73.53	98.16	91.83	81.98	82.95	98.60	65.22	96.78	97.55	103.80	77.76	85.24
Billing kW (Calc)	4,728.00	3,060.00	2,358.00	3,294.00	4,722.00	4,722.00	4,752.00	4,674.00	4,710.00	4,704.00	3,372.00	3,246.00	48,342.00
Load Factor - %	63.79	73.53	98.16	91.83	81.98	82.95	98.60	65.22	96.78	97.55	103.80	77.76	85.24
Energy kWh	2,244,000	1,512,000	1,722,000	2,178,000	2,880,000	2,820,000	3,486,000	2,268,000	3,282,000	3,414,000	2,520,000	1,878,000	30,204,000
Base	159,034.96	106,567.01	103,109.41	134,096.03	184,496.69	182,424.74	209,550.88	158,780.52	198,147.00	203,478.00	148,842.00	120,819.00	1,909,346.24
Energy	92,004.00	61,992.00	70,602.00	89,298.00	118,080.00	115,620.00	142,926.00	92,988.00	134,562.00	139,974.00	103,320.00	76,998.00	1,238,364.00
PCA	66,198.00	44,604.00	50,799.00	53,361.00	70,560.00	69,090.00	85,407.00	55,566.00	80,409.00	66,573.00	49,140.00	36,621.00	728,328.00
Total Revenue	317,236.96	213,163.01	224,510.41	276,755.03	373,136.69	367,134.74	437,883.88	307,334.52	413,118.00	410,025.00	301,302.00	234,438.00	3,876,038.24

Billing kW values based on Ratchet 0% for months 1 through 12.
Active Status based on kWh or Revenue.

TRANSMISSION DELIVERY LEVEL CUSTOMER
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
NCP	4722	3,060.00	2,358.00	3,294.00	4,722.00	4,722.00	4,752.00	4,674.00	4,710.00	4,704.00	3,372.00	3,246.00	48,336.00
CP	4728	4,764.00	2,388.00	4,716.00	4,734.00	4,740.00	4,752.00	4,686.00	4,716.00	4,716.00	4,038.00	4,128.00	53,106.00

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01750A-11-0136

EXHIBIT
MEC-3

REBUTTAL TESTIMONY OF

MICHAEL W. SEARCY

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

February 23, 2012

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REBUTTAL TESTIMONY OF
MICHAEL W. SEARCY
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

SUMMARY OF REBUTTAL TESTIMONY

Mr. Searcy is a Managing Consultant for CH Guernsey & Company, the consulting firm retained by Mohave Electric Cooperative Incorporated to assist in the preparation and processing of its rate application. In his rebuttal testimony Mr. Searcy discusses:

1. Staff's use of a 2010 test year (instead of the 2009 test year used by Mohave);
2. Adjustments to "other revenue" and rate case expense;
3. The general consensus on revenue requirement, rate design and Mohave's service rules and regulations except for differences relating to:
   a) Implementing a pre-paid service program,
   b) Recovering transformer costs from new customers outside subdivisions,
   c) The time period Mohave will apply its existing line extension policies to persons receiving a written estimate prior to a Decision in this case,
   d) The level of residential customer charge,
   e) The on-peak periods for the residential time of use rate,
   f) The design of large commercial and industrial time of use,
   g) Staff's capping the residential class revenue requirement at the overall percentage rate increase; and
   h) Staff's request that Mohave be ordered to file its next rate case no later than April 1, 2016 using a 2015 test year.

Mr. Searcy demonstrates that Mohave's position regarding each of the foregoing issues is superior to the position advocated by Staff and should be adopted by the Commission. Mr. Searcy further demonstrates that as the duly elected representatives of the customers Mohave serves, the determinations and preferences of the Mohave's Board of Directors should be given substantial weight and deference.

1. INTRODUCTION

Q. Please state your name, your employer and your position.

A. My name is Michael W. Searcy and I am employed by C. H. Guernsey & Company ("Guernsey"). My current position is Managing Consultant. I have previously presented Direct and Supplemental Testimony in this matter on behalf of Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative").

2. PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the direct testimony submitted by Staff on the following issues:

1. Staff's test year;
2. Staff's $55,820 increase to other revenues;
3. Staff's omission of rate case expense and recommendation that Mohave be ordered to file its next case no later than 2016;
4. Staff's exclusion of both power costs and margins related to third party sales;
5. Staff's recommended revenue requirement;
6. Staff's recommendations on Mohave's service rules and regulations, including line extension policy and prepaid metering service;
7. Staff's comments regarding Mohave's cost of service study; and
8. Staff's class revenue and rate design recommendations.

3. SELECTION OF TEST YEAR

Q. What test year did Mohave use?

A. Mohave selected the 2009 calendar year for its test year as it was the most recent audited data available when the application was being compiled. The actual test year was then adjusted for known and measurable changes of a continuing nature. At Staff's request, Mohave supplemented its application with actual 2010 calendar year data with adjustments to reflect: a) AEPCO's new wholesale power rates, b) updated third party sales power cost and revenue projections, c) the expiration of a special contract rate applicable to a single large customer and d) the PPCA revenues flowing from the power cost changes. In my supplemental direct at page15, lines 11 – 25, I explained that the supplemental 2010 data served to demonstrate the reasonableness of the 2009 test year Mohave had selected.

Q. What test year has Staff chosen to use?

A. Staff elected to use the largely unadjusted 2010 calendar year data suggesting it, "*reflected the most recent historical 12 month period, consistent with Commission* Rules, and provided Staff with more recent information to perform its analysis. Staff updated the test year to 2010." (Direct testimony of Crystal S. Brown, page 4, lines 12 – 14.)

Q. Does Mohave agree with Staff's use of the 2010 test year?

A. Certainly 2010 is more recent than 2009. Mohave does not necessarily agree that 2010 is more representative than 2009 or that this change in test year is necessary. However, because the bottom line revenue recommendation of Staff, after making the few necessary adjustments to the 2010 operating revenues and expenses I will specifically discuss, will result in substantially the same revenue requirement as requested by the Cooperative, Mohave will not dispute Staff's use of a 2010 test year.

4. STAFF ADJUSTMENT TO "OTHER REVENUE"

Q. Did Staff recommend an adjustment to Mohave's proposed "Other Revenue?"

A. Yes. Staff witness Crystal Brown accepted Mohave's adjusted 2010 test year "Other Revenue" of $606,899. However, in adjusting for the impact of the revised service fees proposed by the Cooperative, Ms. Brown increased the "Other Revenue" adjustment by $55,820, from $256,648 to $312,468. In her testimony (Direct Testimony of Crystal S. Brown, Page 13, line 10 – Page 14, line 3), she states this was to include $55,820 in additional revenue from a new service charge that was not included in Mohave's proposed revenue requirement.

Q. Is the $55,820 "Other Revenue" adjustment appropriate?

A. No. Based upon communications with Staff, I believe Ms. Brown may have misunderstood my response to data request CA 5.13 involving the computation of revenues from a new deferred payment plan late fee. In my response, I stated, in part:

> *"In the course of developing the response to this question, an error in the data was discovered... The original projected amount was $56,537. The revised amount is $55,820. The $717 difference is not material."*

The intent of the answer provided was to indicate that the portion of Mohave's proposed "Other Revenue" increase associated with revenue generated by the new late fee, if adjusted at all, should be lowered by $717, not increased by $55,820.

Q. What is the appropriate level of 'Other Revenue' for the adjusted 2010 test year?

A. In responding to Staff's Data Request 5, Mohave discovered other small service charge corrections that were provided to Staff as a part of Data Request 5. Attached as MWS-Rebuttal Schedule 1 is a summary of "other revenue" as originally proposed by Mohave and with all corrections submitted to Staff. The total 2010 test year "Other Revenue" amount, adjusted for the new rates, is $867,282. This reflects an increase of $260,383 over the adjusted test year amount, or $3,735 more than reflected on Mohave Supplemental Schedule A-1.0. The final corrected amount for "Other Revenue" is $52,085 less than reflected on Schedule CSB-3 to Ms. Brown's direct testimony.

Q. Would such an adjustment require further changes beyond an adjustment to "Other Revenue?"

A. Yes. Any revenue not collected from service charges/other revenue must be recovered from base rates. This will involve slight changes in base rates for the rate classes and will affect the final rates and tariffs to a slight degree. Mohave has included these changes in its Rebuttal Rates as MWS-Rebuttal Schedule 6.

Q. Is it your understanding Staff agrees with Mohave's adjusted "Other Revenue" figure?

A. Yes. It is my understanding Staff agrees with Mohave about making this revenue change and will include both the reduction in "other revenue" and the corresponding increase to base rates as a part of its surrebuttal testimony.

5. RATE CASE EXPENSE/NEXT RATE FILING

Q. Did Staff include any amount for rate case expense in its adjusted 2010 test year income statement?

A. No. As noted, Mohave intended to rely on the 2009 test year which included $150,000 in rate case expense amortized over 3 years. This amount was not carried over to the supplemental 2010 data, since Mohave was not proposing to use it for rate making purposes. Since Staff is using the 2010 test year, Staff should have also included a reasonable sum for rate case expense.

Q. Was any amount of rate case expense included in the actual 2010 expenses Staff is using for the 2010 test year?

A. No. Mohave set up a deferred account, so none of these expenses is included as a part of Mohave's 2010 expenses and none is included as a part of Mohave's 2010 income statement.

Q. What amount is Mohave requesting as rate case expense?

A. Mohave is requesting $400,000 amortized over 4 years as rate case expense resulting in $100,000 being included in the test year. Of this amount, $341,090 had actually been incurred by January 31, 2012 and the rest is the current projected costs to conclude this matter.

Q. What has caused Mohave's rate case expense to increase over its original projections?

A. Staff's request for supplemental 2010 data and Staff's decision to conduct a purchase power prudence review as part of this rate case have significantly increased rate case costs beyond those initially projected by the Cooperative. Mohave agreed to provide the supplemental 2010 data and to provide four years of significant power cost data. Mohave timely objected to Staff's request to go back an additional 5 ½ years as part of its purchase power prudence review because it is unduly burdensome, had been previously provided to Staff in the form of monthly purchase power filings and is well beyond the customary scope of the historical test year (whether 2009 or 2010) used to set rates in this proceeding. Without seeking an order to compel, Staff, through its consultant Mr. Mendl, is recommending the Commission impose a $1.946 million penalty, as a prudence adjustment "because MEC failed to maintain and provide the information to support the prudence of its purchased power" for the period between July 25, 2001 and December 31, 2006. (Direct Testimony of Jerry Mendl, pp. 26-28). Mohave is working with Staff in an effort to resolve this issue, but as of the deadline for filing rebuttal testimony, the issue is contested and is consuming significant time and effort on the part of Mohave.

Q. **Would such an adjustment require further changes beyond an adjustment to operating expenses?**

A. Yes. The recommended increase in operating revenue would need to be increased the same amount as the amount of rate case expense included the adjusted test year to attain the operating margins recommended by Staff. <u>This is reflected on MWS-Rebuttal Schedules A-1 and A-2.</u>

Q. **Why is a four year amortization period appropriate?**

A. Staff is recommending Mohave be ordered to file a new rate case no later than April 1, 2016 based upon a test year ending December 31, 2015. As rates will not go into effect until July or August of 2012, there will be approximately 4 years to collect the rate case expense under the rates approved in this proceeding, based upon Staff's recommendation.

Q. **Does Mohave support Staff's recommendation that the Commission require the Cooperative to file a rate case no later than April 1, 2016 with a test year ending December 31, 2015?**

A. While Mohave agrees it likely that a rate case will be appropriate by that period, the Cooperative opposes being ordered to make a rate filing by a date certain or having its test year determined in advance of such filing. Mohave believes its member elected Board of Directors is better able to determine when a rate filing is necessary and that such decision, and the appropriate test year, should be based upon actual operational data. Moreover, Mohave has an annual audit done by an outside certified public accountant. The results of such audits are usually not presented to the Cooperative's Board until June or July following the close of the calendar year being audited. Therefore, requiring a filing before September1 would not allow Mohave to base its filing upon audited data.

Mohave would not object to being required, as a compliance item, to file in this docket on or before April 1, 2016 a copy of its unaudited Form 7 for the calendar year 2015, together with a summary schedule containing the information contained in Schedule CSB-1 reflecting an estimate of any increase in rates the Cooperative's management anticipates might deem appropriate, unless prior thereto it has already separately docketed a rate case.

6. <u>POWER COST, PPCA BASE COST, BASE REVENUE & PPCA REVENUE</u>

Q. Did Staff recommend an adjustment to Mohave's adjusted 2010 Power cost, PPCA base cost and Base Revenue and PPCA Revenue?

A. Yes. Staff witnesses Crystal Brown and Jerry Mendl recommended removing recovery of $594,737 in expenses related to power supply from power cost and from recovery through the PPCA. All but $32,702 of these expenses were found to be justified and transferred to Mohave non-power cost expenses. Mohave is not disputing removal of the $32,702 from adjusted 2010 test year expenses. As discussed further by Carl N. Stover in his rebuttal testimony, Mohave does oppose Staff's exclusion of the remaining $562,035 in costs from power supply related expenses, as well as Staff's proposal that in the future Mohave exclude from PPCA calculations both power cost and margins received from third party sales (TPS), as opposed to its current practice of excluding only power cost.

7. <u>REVENUE REQUIREMENT</u>

Q. What is the net impact on Mohave's revenue requirement and how does that compare to Staff's recommendation?

A. Regardless of whether the Commission agrees with Mohave or Staff relating to the treatment of these items in PPCA calculations, Mohave's revenue requirement for the adjusted 2010 test year is $79,073,715, (<u>MWS-Rebuttal Schedule A-1</u>) as compared to Staff's recommended revenue requirement of $78,973,715 (Staff Schedule CSB-3). The total difference is $100,000 and is entirely related to including recovery of rate case expense.

Since total revenue required by the Cooperative is not in dispute, any increase or decrease in PPCA revenue will require an off-setting decrease or increase in the base rates and revenue. Attached is <u>MWS-Rebuttal Schedule A-1</u>, showing Mohave's proposed change to Staff's recommended income statement shown on Staff Schedule CSB-3. Changes made were to 1) correct "Other Revenue", 2) add rate case expense, 3) restore Mohave's treatment of power-supply-related expense as power cost and recover these costs through the PPCA rather than base rates, and 4) restore Mohave's treatment of third party sales margins and <u>not</u> refund these margins to members through the PPCA. While the changes affect the items listed above, operating margin and return developed under Mohave's rebuttal income statement and under Staff's income statement are identical. <u>MWS-Rebuttal Schedule 4</u>, shows the calculation of Mohave's base PPCA cost continuing Mohave's existing treatment of power-supply-related expenses and third party sales margins and rejecting Staff's recommended changes in these areas.

8. STAFF ADJUSTMENTS TO MOHAVE'S POLICIES, INCLUDING ITS LINE EXTENSION POLICY AND PREPAID METERING

Q. Does Mohave agree with Staff's recommended changes to its service rules and regulations?

A. Mohave will adopt all the changes to its policies recommended by Staff, other than those I will discuss separately related to line extension and the recommendation that Mohave make a separate application for its prepaid metering option.

Q. Did Staff recommend any changes to Mohave's proposed line extension policy with which Mohave does not agree?

A. Yes. While Mohave and Staff are in almost total agreement with regard to MEC's policies, Mohave does not agree with two of Staff's recommendations regarding its proposed line extension policy:

1) "Mohave [should] not charge the cost of the transformer to individuals not within a subdivision requesting single phase or three phase service" (Direct Testimony of Candrea Allen, Recommendation 5, Page 9, Lines 18 - 20), and

2) "any potential customer who has been given the current line extension free footage allowance estimate or quote by Mohave up to one year prior to an Order in the matter should be given the line extension free footage allowance as specified in Mohave['s] current Service Rules and Regulations, as discussed in the testimony." (Direct Testimony of Candrea Allen, Recommendation 7, Page 9, Lines 26 – 30).

Q. Please explain why Mohave feels it is appropriate to include the cost of the transformer in calculating line extension allowable investment for those outside of subdivisions in particular.

Mohave's line extension policy is designed to recover, through a combination of revenue from the member over time and as up-front contributions in aid of construction, each member's share of the cost of providing line extension to serve their facilities. Staff agrees with this general concept. Witness Candrea Allen on page 6, lines 22 – 23 states: "Staff believes that Mohave's proposed line extension allowance would be beneficial for its customers." Transformers are part of the plant investment whether installed to serve a subdivision or individual lots.

Unlike heavily urban utilities, Mohave is a rural electric cooperative. Mohave serves many residential customers outside of urban areas and outside of subdivisions. While rural growth is typically slower than in urban areas, residential customers do request service outside of subdivisions, including quite rural parts of the cooperative's service territory. They are in areas of low customer density where each customer typically requires their own individual service transformer, rather than a typical subdivision where multiple customers are more often connected to a single transformer. So the average per-customer transformer plant investment is often greater outside of subdivisions. Removing recovery of the Cooperative's investment in transformation facilities from any group creates a subsidy.

Mohave believes its proposed method, including full recovery of transformer plant investment from customers outside of subdivisions is fairer to all cooperative members and requests that its proposed line extension policy be approved as submitted.

As an alternative, Mohave suggests that outside of subdivisions, the customer's responsibility for transformer costs be capped at one half of the transformer's cost. This ensures that individual will share at least one half the transformer cost with either another customer/neighbor or the Cooperative. Where a transformer is expected to serve more than two members, an individual member would only be responsible for his or her pro rata share.

Q. Is Staff's recommendation that customers who have received a line extension estimate be given a year to proceed under the existing line extension policy necessary or appropriate?

A. No. Today, each member is provided a written estimate on a standard printed form identifying the cost on any line extension to a member requesting line extension. A copy of this standard form is attached and included as <u>MWS-Rebuttal Exhibit 2</u>.

The form states on page 1, Section I, Item 1 the following:

> *"This estimated construction cost is valid for 60 (sixty) calendar days from ________. The full estimated cost of construction must be paid, this agreement must be executed, and Mohave's construction must be started within that 60 (sixty) days, or this agreement may be declared null and void at the option of Mohave."*

To the extent Staff is concerned that a customer might see an unexpected increase in the cost of extension of electric service due to the policy changes, they are already on written notice that the estimate is only good for sixty (60) days.

Q. Does Mohave recommend revisions to the wording of Staff's recommended change to Mohave's proposed line extension policy?

A. Yes. Mohave believes that recommendation 7 as referenced in the direct testimony of Candrea Allen, page 9, lines 26 – 30 is unnecessary and should be eliminated. If, however, the Commission feels some additional customer protection is needed, Mohave suggests the recommendation and order provide:

> "Any potential customer who has been given the current line extension free footage estimate or quote by Mohave up to sixty (60) days prior to an Order in this matter shall be given the line extension free footage allowance as specified in Mohave's current Service Rules and Regulations for up to sixty (60) days after the effective date of such Order."

The foregoing will have the effect of extending the validity of the original estimate for a period of sixty (60) days following the date the policy changes are effective. Mohave will include in its customer notice concerning the rate change the following statement:

> "The Commission has also approved changes to Mohave's line extension policy. Mohave will continue to honor written line extension estimates received on or after 60 days prior to the date of the Decision (i.e., on or after _____) for an additional 60 days (i.e., until ______). Thereafter, all line extensions will be calculated based upon the revised line extension policy."

Q. Were there other policy matters addressed by the Staff?

A. Yes. Staff recommended several changes to Mohave's policies and recommended that Mohave's request to implement prepaid metering be considered separately and not as a part of this proceeding.

Q. Why does Mohave not wish to see the prepaid metering request be handled at a later date as a part of a separate proceeding?

A. Mohave does not wish to delay implementation. Mohave is not proposing a separate or different rate be applied to pre-paid metering customers. And Mohave is not proposing that pre-paid metering be considered as a part of its DSM program, either as assumed reductions in usage or for cost recovery through its proposed DSM adder.

Mohave is proposing that it be allowed to implement prepaid metering for a single reason, to allow members with an option to putting up a security deposit, without placing the cooperative's financial position at risk. Customers taking part in prepaid metering will not have to put up a security deposit, and many customers have strongly requested their cooperative implement this program.

The prepaid metering program would not affect revenue.

Q. Does Mohave anticipate that implementing prepaid metering would result in a reduction in its annual write-offs as recorded in Account 904?

A. Mohave has no idea how many members whose accounts might result in write-offs would take part in prepaid program, and therefore, the amount of any adjustment is not known or measurable.

9. STAFF REVIEW OF THE COST OF SERVICE STUDY

Q. Did Staff conduct its own cost of service study (COSS) for Mohave?

A. No. Staff reviewed, commented on and relied on the COSS submitted by Mohave. Staff witness Bentley Erdwurm states Mohave's COSS presents, "a traditional fully allocated cost of service study ("COSS"), along with Mohave's proposed rate designs." (Direct testimony of Bentley Erdwurm, page 2, lines 6 – 7) "It is <u>not</u> the position of Staff that Mohave's proposed functionalization, **classification**, and allocation techniques used in its proposed COSS fall outside the bounds of standard industry practice . . ." (Direct testimony of Bentley Erdwurm, page 9, lines 7 – 9; underline in original; bold emphasis added.)

Q. According to Staff, how does Mohave's classification approach affect its rate design proposals?

A. According to Staff's witness Bentley Erdwurm, Mohave's use of distribution items separate from the functions of metering, meter-reading, the service drop, and customer service, "inflates its proposed residential customer charge to $16.50 per month, which is in excess of a more appropriate charge of $12.00 per month supported by Staff." (Direct testimony of Bentley Erdwurm, page 9, lines 12 – 19)

Q. Do you agree with this assessment of Mohave's COSS offered by Staff?

A. No. The COSS classification methodology used is consistent with standard industry practice and does not "inflate" the residential customer charge. In fact, Staff's proposed rate design uses Mohave's classification methodology for all rate classes, except for residential and large industrial and commercial time of use customers. The same classification methodology described by Staff as "not acceptable," (Direct testimony of Bentley Erdwurm, Page 9, line 14) was used to develop cost classification in two previous TRICO rate cases, one previous SSVEC rate case and one previous Navopache rate case. In each of these cases, the COSS was prepared by Guernsey and Staff recommended approval of the COSS, although with some deviation in rate design.

In addition, Guernsey has used the same methodology for cases presented and approved without changes in recent years by Wyoming, Arkansas, and New Mexico regulatory Commissions, along with numerous states where cooperatives are regulated by their elected boards, including Colorado, Florida, Georgia, Kansas, Minnesota, Mississippi, Missouri, Nebraska, Oklahoma, and Texas.

This issue is important because Staff recommends Mohave have a significantly lower residential customer charge than the $18.50 residential customer charge the COSS demonstrates is properly recovered by the customer charge. The $16.50 residential customer charge proposed by the Cooperative moves toward, but not to the actual customer-related cost the COSS indicates Mohave incurs in making electricity available to individual residential customers.

Q. Please explain the basis of a COSS for an electric distribution cooperative?

A. Classification of costs is in effect a "bucket" that categorizes each cost. There can be many classifications for distribution cooperatives, but they typically are summarized into three main cost components: 1) power supply (demand-related and energy-related), 2) customer-related, and 3) capacity-related. The last two are the costs of operating Mohave's own distribution, substation and subtransmission systems. No power supply related costs are included in these last two components.

To the extent changes in rates move a cooperative closer toward recovering costs in a similar manner to how costs are incurred, rates are generally fairer to customers, and provide a cooperative with a more secure revenue source that causes the cooperative less financial disincentive to promote renewables, energy efficiency and conservation (decoupling).

Electric cooperatives have quite different customer mixes than is typically the case with investor-owned utilities. Electric cooperatives nearly always include a greater percentage of their systems in rural areas than is true of more urban utilities. Mohave, for example, serves rural territory in the Kingman area, while an investor-owned utility, UNS, serves most of Kingman itself. Cooperatives have stretches of rural line with quite low line density that often serve a high percentage of loads such as barns, stock wells, etc. with low usage – yet no matter how low the density, or how low the usage for each customer on a rural line, at least some minimum size of poles and wire must be used and some minimum size of transformer must be hung.

This minimum size of facilities, therefore, is driven not by the customer's capacity, but by his or her simply being a customer – and the only way the Cooperative can recover these costs from such an extremely low usage customer is through the customer charge.

Q. **Has the Commission recognized the foregoing COSS attributes in approving rates for electric distribution cooperatives?**

A. The same classification methodology described by Staff as "not acceptable," (Direct testimony of Bentley Erdwurm, Page 9, line 14) was used to develop cost classification in two previous TRICO rate cases, one previous SSVEC rate case and one previous Navopache rate case. In each of these cases, the COSS was prepared by Guernsey and Staff recommended approval of the COSS, although with some deviation in rate design.

In Decision No. 71230, dated August 6, 2009, the Commission expressly recognized that customer service costs "includes ***the customer component of distribution line expense, a portion of the transformer expense,*** [in addition to] the meter and service drop expense and meter reading and customer records expenses." Decision at p. 7, lines 17-20. Where the only disputed issues with Staff involved rate design, the Commission approved Trico Electric Cooperative's request for a $15.00 per month residential customer charge and rejected Staff's lesser increase to $13.50.

Q. **Staff indicates that Mohave's cost classification, if implemented in rates, "creates a price signal that runs counter to encouraging the efficient use of electricity." (Direct Testimony of Bentley Erdwurm, page 9, line 24) Do you agree?**

A. No. In fact, Mohave has proposed a $16.50 customer charge that moved it closer to the $18.50 reflected in the COSS in lieu of seeking the more complex decoupling mechanisms proposed by Arizona Public Service Company and Southwest Gas because it provides the customer a simpler and cost based price signal. Before doing so, Mohave considered the impact on its residential customers of moving its residential customer charge to $16.50. The impact was moderated both by the limited overall increase being sought for the residential class and by moving to a three tier energy rate design from the existing single energy rate design. Moreover, the first tier of energy rates for usage from 0 to 400 kWh per month reflects de minimis usage rather than that of normal occupied residence, especially during the hot summer months in the Cooperative's service area. Mohave's proposed rates targeted residential customers with energy usage of between 400 to 2,000 kWh to experience a limited increase in their overall electric bills ranging from 3.94% to 3.72% (i.e., below the overall increase originally requested). See, Supplemental

Schedule H-4.0. Because of the Staff-recommended increase in energy charges between the blocks, under Mohave's rebuttal rates, residential customers with energy usage of 400 kWh will experience an increase of only 0.46% as compared to usage under existing rates. Customer with usage of 1,000 kWh per month would actually see a small decrease of 0.77%. See MWS-Rebuttal Schedule 8. In contrast, Staff's proposed residential rate design customer charge would require other members to subsidize those members who can afford to leave the service area for a part of the year (particularly in the summer months for vacations or summer residences) because these customers often have several months in the year with little or no usage.

Mohave is committed to promoting the efficient use of electricity and has taken several measures to accomplish this. Two examples include its proposed rates with inclining blocks and its long-standing rebates for energy efficient HVAC equipment. But Mohave does not believe the best method of promoting energy efficiency is to recover its fixed cost of providing service through energy charges.

All of Mohave's cost of providing service is fixed cost – either driven by customer-related factors or by peak capacity on facilities. Shifting cost classification from fixed customer-related cost classification to some other fixed cost classification as recommended by Staff does not change this. In particular, recovering fixed customer-related cost through variable (energy) billing units is not fair to all customers and places cooperative margins at risk in years with low usage.

Cooperatives are quite small and have relatively little industrial load as compared to investor-owned utilities. This makes them extremely vulnerable to the changes in margins that occur when fixed costs are recovered through variable billing units that are highly dependent on weather, the economy, and the cooperative's own promotion of renewables, energy efficiency and conservation.

In addition, recovering fixed customer-related costs through variable energy rates runs counter to the PURPA standard that promotes decoupling in rate making. Mohave believes that the simplest, most logical, and easiest to understand method of decoupling rates, particularly for a small electric cooperative, is by recovering much of its fixed customer-related cost of providing service through fixed customer charges instead of through variable energy charges. If rates are not decoupled, as Mohave continues to succeed in promoting energy efficiency, margins will continually fall and new subsidies will be created.

Finally, Mohave believes long-standing, industry standard and historically Staff and Commission approved COSS classification methodology should not be modified to produce a result. For example, if Staff were to believe Mohave has requested a customer charge that produces what it considers to be an unacceptable increase, the focus of discussion should be entirely on that customer impact issue, rather than suggesting that the COSS be modified to show justification for a lower customer charge.

Mohave's elected Board of Directors deems its proposed movement toward cost of service as demonstrated in the COSS, including its increased residential customer charge, coupled with a three tier energy charge and the absence of a decoupling mechanism, to be fair and reasonable for its members.

Q. What is Mohave's recommendation with regard to the COSS?

A. Mohave recommends the COSS be approved as prepared and without changes, including classification of costs.

10. STAFF REVENUE CHANGES BY RATE CLASS

Q. Do Staff and Mohave agree as to Mohave's system revenue requirement and Mohave's requested rate change request?

A. Adjusted for rate case expense and properly accounting for "Other Revenue", the system revenue requirement proposed by Mohave and Staff are very similar. See MSW-Rebuttal Schedule A-1.

Q. Does Staff recommend changes to Mohave's proposed revenue allocation to the various rate classes?

A. Yes. As shown on Staff Exhibit DBE-1, Mohave's proposed increase to the residential rate class of 4.07% has been reduced to 3.81%. Staff witnesses Bentley Erdwurm states in direct testimony on Page 5, beginning on line 16, "Staff believes that the residential percentage increase should not exceed the system percentage increase, unless compelling cost considerations indicate otherwise."

Q. Does Mohave agree with Staff that the "residential percentage increase should not exceed the system percentage increase?"

A. No. Such a cap on the allocation of revenue responsibility to the residential class a) is arbitrary, b) is unsupported by the record, c) is contrary to the Public Utility Policy Act's intent to structure rates that, to the maximum extent practicable, will reflect the costs of service to each customer class, d) ignores the minimal amount of additional revenue Mohave is proposing to shift to the residential class, e) foregoes the opportunity to make such shifts when the overall increase request is minimal, and, f) if followed consistently, would forever preclude closing the gap between the residential and other customer classes.

Mohave believes, given the long regulatory history of basing cost recovery from the rate classes more closely to how each class incurs costs, that it should be assumed that, while balancing the impact on customers, a cooperative will move each rate class closer to cost of service UNLESS there is a compelling cost consideration or a practical reason not to do so. Imposition of an arbitrary cap is not a compelling cost consideration to preclude the movement of the residential class somewhat closer to paying its actual cost of service.

On Schedule G-2.1 of the original filing, relative performance of each rate class with and without Mohave's proposed rate change is shown. Prior to any rate changes, the residential rate class relative rate of return (RROR) is 0.2. Any RROR number less than 1 means a rate class is receiving a subsidy provided by other rate classes. After Mohave's proposed rate change, the residential RROR is 0.72. Mohave has balanced the impact on residential customers, therefore, and while not proposing an increase to the residential class large enough to bring the residential class RROR up to the system average, has proposed that a small step in that direction be made. Mohave is over 90% residential. If Staff's position is that Mohave can never increase its residential rate class by a percentage increase above the system average percentage increase, Mohave will never be able to close the gap that exists between residential and other rate classes.

As shown on Staff Schedule DBE-1, the difference between Mohave's proposed revenue from the residential rate class and Staff's recommended revenue from the same class is only $110,090. Staff indicates the small difference is a reason to adopt their suggested change. Mohave believes the small difference is an insufficient reason to step away from its proposed modest step toward cost-based class revenue.

Furthermore, the best time to correct subsidies between rate classes is when the over-all rate change is small. The total proposed rate increase is less than 4%. Taking a quite small step now toward reducing subsidies between rate classes will result in less customer impact than waiting for some future rate case when the over-all change might be higher.

For the foregoing reasons, Staff's suggestion "there exists no practical reason that the residential percentage increase cannot be capped at the system increase" (Direct Testimony of Bentley Erdwurm, p. 5, lines 22-23) is wrong.

Q. Other than the residential rate class, does Mohave disagree with the revenue allocation changes Staff proposes for any other rate classes?

A. Yes. Mohave also objects to Staff's proposed change to the Large Commercial & Industrial time of use rate (LC&I TOU) class. Mohave's disagreement will be discussed below as a part of the rate design testimony. In addition, adjusting "Other Revenue" and adding rate case expense will necessitate a small change in the total revenue requirement from Staff's recommended totals allocated to the various rate classes.

Q. What is Mohave's proposal with regard to the class revenue requirement?

A. Mohave believes the proposed class revenue requirements should be as provided on the attached MWS-Rebuttal Schedule 5.

11. PROPOSED STAFF RATE DESIGNS

Q. Did Staff recommend changes to Mohave's proposed rate designs?

A. While Staff generally followed the rate designs proposed by Mohave, Staff did recommend some changes as illustrated on Staff Exhibit DBE-3. Mohave does not oppose:

1. Increasing the charge between residential energy blocks 15 mills per block instead of 10 mills per block.
2. Adjusting the rate designs to reflect changes to the base power cost and to achieve the overall revenue requirement authorized by the Commission, (although not agreeing with the specific base power cost and revenue requirement proposed by Staff).
3. An inclining energy rate in the TOU rates.
4. Changing the on-peak period for the optional residential time of use (RES TOU) rates that include weekends.
5. Subject to adjustments for base power costs and the final overall revenue requirement, the rate designs for Small Commercial, Large Commercial & Industrial, Irrigation and Lighting customers.

Despite general agreement on rate designs, Mohave does oppose Staff's proposals relating to:

1. Residential customer charges.

2. A dramatic revision to the LC&I TOU rate required to cap the overall increase in revenues from the three (3) customers on this rate to 26%, versus the 40% proposed by Mohave.

3. A change to the on peak period for the RES TOU, excluding weekends.

4. While Mohave agrees with establishing differential-based customer charges between the standard rates and the RES TOU rate, the RES Experimental demand rate, the Small Commercial Energy rate and the Small Commercial TOU rate, Mohave does not agree with Staff's recommended amount of differential.

Mohave's rebuttal rate designs are developed on attached MWS-Rebuttal Schedules 6, 6a and 6b and summarized on attached MWS-Rebuttal Schedule 7. Revisions to the proposed PCA base cost are shown on attached MWS-Rebuttal Schedule 4. The differences with Staff are discussed in more detail below.

12. RESIDENTIAL RATE DESIGNS

Q. What changes did Staff make to Mohave's proposed residential rate?

A. Staff recommended:

1. A decrease in the customer charge from Mohave's proposed $16.50 per month to $12.00 per month.

2. Bundled inclining energy blocks to be increased by a total of 15 mills per block instead of Mohave's proposal of 10 mills per block.

3. Unbundled rate designs to include inclining block for power supply as well as wires cost recovery.

In addition, as was the case with all rates, Residential rates were modified to reflect the Staff-recommended change in base power cost and total revenue requirement.

Q. Does Mohave agree with Staff's proposal for a $12.00 per month residential customer charge?

A. No. As previously explained in the COSS section, Mohave disagrees with Staff's interpretation of its customer cost classification. Mohave believes its COSS classification as filed is sound, accurate, and reflects standard industry and historical practice for cooperative cost classification across the country, and in Arizona. Staff has agreed Mohave's approach falls within the bounds of standard industry practice. Staff's primary concern is the percentage impact the rate design will have on customers using a nominal amount of energy (0 to 400 kWh per month).

Mohave took into account customer impact in considering an appropriate level for the customer charge. Mohave's elected Board of Directors determined $16.50 is a good balance of moving cooperative rates closer to the cost-based $18.50 rate demonstrated by Mohave's COSS (see, Schedule G-6.0, p. 1), moving rates closer to the PURPA decoupling standard, and reducing subsidies from one residential member to another, while minimizing customer impact.

Importantly, customer billings reflecting energy usage of less than 400 kWh can often be explained by absence from the home (e.g., for vacations or use of second homes), a partial month's billing, or by a rental home being vacant, rather than a consistent level of usage. Mohave's service area has high level of turnover, so billings for part of a month are numerous. Customers that can afford to do so will leave the service territory during the hotter summer periods minimizing their energy usage for that period. Mohave deems it inappropriate for the rest of the membership to subsidize these customers and have proposed a customer charge and tiered rate blocks to avoid such subsidization.

Mohave's proposed changes to energy charges are closely linked to customer charges. Mohave proposed an inclining block rate. This rate helps offset the impact of the proposed customer charge increase on low usage customers, since the inclining block change in rate falls most heavily on customers with highest usage and reduces the per kWh charge that would otherwise be applied to customers with low usage. In agreeing to Staff's recommended increase in the inclining energy block charges, Mohave's rebuttal rate designs even further offset the impact of the customer charges because of the higher per-block increase.

Mohave's over-all rate request is under 4%. Mohave feels that the best time to address inequities between and within rate classes is when the over-all rate change is low.

Q. **What would Mohave's rebuttal residential rate look like?**

A. Mohave's rebuttal residential rate design is attached as <u>MWS-Rebuttal Schedule 6</u>. The comparison of existing, originally proposed, Staff recommended and Mohave rebuttal rates is shown as <u>MWS-Rebuttal Schedule 8</u>. As shown, Mohave's rebuttal rates, without any phasing, result in the average customer with usage of 860 kWh per month seeing a slight decrease of -$0.63 per month or -0.62% as compared to existing rates. A customer with median usage of 637 kWh would see a decrease of -$0.21 per month or -0.27%.

The rebuttal rate provides a strong pricing signal promoting energy efficiency through its inclining block rate – which under the rebuttal rates incline more steeply than originally proposed.

As was the case with all rates, Residential rates were modified to reflect rebuttal base power cost and total revenue requirement.

Q. Would Mohave be willing to phase in its requested change in customer charge over time?

A. Mohave proposed a $16.50 customer charge for the residential class because that is the level its elected Board of Directors deems appropriate after balancing the factors I have discussed. If the Commission deems such a rate change is too large in one step, then Mohave would be willing to work with Staff to develop a phase in plan leading to its proposed $16.50 customer charge over a period of years. If this approach is selected by the Commission, Mohave proposes starting with Staff's proposed customer charge of $12.00 on the effective date of the new rates, and then over the next two years commencing with November usage in 2013, increase the customer charge an additional $2.25 each year and lower the energy charges for each rate block so that, based upon test year billings, the authorized revenue for the residential class was produced. November is selected because this is a period when energy usage is normally close to its lowest. In this manner the full customer charge would be implemented with November usage of 2014.

Q. What would the phased rates discussed above look like?

A. <u>MWS-Rebuttal Schedule 7</u> shows the phasing set forth above. <u>MWS-Rebuttal Schedule 8</u> shows comparisons under the phases at different usage levels.

13. RESIDENTIAL TIME OF USE RATE AND NET METERING CUSTOMER CHARGE

Q. What changes did Staff recommend to Mohave's RES TOU rate?

A. Staff did not provide a copy of a suggested RES TOU rate. In testimony, Staff recommended a decrease in monthly customer charge from Mohave's proposed $21.50 per month to $15.00 per month (which is the existing customer charge for RES TOU). Staff recommended changes in summer on-peak hours and agreed with Mohave's proposed winter on-peak hours.

Staff indicated it was important for Mohave's RES TOU rate to have inclining blocks similar to those in the standard RES rate. Mohave agrees with this last statement.

As was the case with all rates, the RES TOU rates were modified to reflect the Staff-recommended change in base power cost and to total revenue requirement.

Q. Does Mohave agree with the Staff recommended customer charge?

A. Mohave agrees that the customer charge for RES TOU customers should be set to collect the cost difference between the standard RES rate and the RES TOU rate. Mohave contends this cost differential is $5 rather than the $3 recommended by Staff.

The proposed customer charge difference between the RES and RES TOU rates is based on the added cost in buying, programming, reading and billing TOU meters as compared to standard meters. Mohave only installs meters for TOU customers that display TOU information. Mohave's cost for a standard AMI meter that will NOT display TOU data is $125. Mohave's cost for a meter and module that will display TOU data is $449. Assuming cost recovery over ten years, depreciation cost alone adds $2.70 per month per customer. Mohave's cost of billing and accounting per standard residential meter is $5.00 per month, according to the COSS (Schedule G-6.0, page 7, original filing). The Cooperative estimates the added cost of customer service, installation, meter reading, billing and accounting for TOU customers would exceed $2.50 per customer per month.

Once the Cooperative has completed installation of its AMI metering system, this cost differential may decrease but such is currently speculation. In 2009 and 2010 deployment of Mohave's AMI metering system was in its early stages and is still an ongoing effort.

Q. Does Mohave agree with the Staff's recommended changes to the on-peak and off-peak hours included in the proposed RES TOU rate?

A. Mohave can support a shortened peak period for both its optional RES TOUs rates, but does not support the same peak period for both.

Mohave's system can and does peak on weekends. Currently, Mohave's optional RES TOU does not include weekends. Thus customers can contribute to Mohave's peak, while receiving a discounted TOU rate. To address this situation, Mohave proposed an innovative second optional RES TOU rate that had shorter peaks and an additional 2.25% discount on energy charges if the customer agreed to include weekends, while maintaining the existing (longer) peak periods if the customer desired to continue to exclude weekends. The basic concept was to balance providing a pricing signal to members with having an easily understandable rate and encouraging members to take part in reducing peak load while minimizing the negative margin effect of "free riders."

Mohave wants to give customers a clear indication that it understands controlling load on weekends might be more difficult or less desirable. So a customer voluntarily choosing the weekend option receives two benefits, he or she has fewer hours per day (though the same number per season) requiring control, and a clearly indicated per kWh credit for any added effort or inconvenience caused by weekend peak load reduction.

Staff's proposal that the same on-peak periods be used for both options (with and without weekends) during the summer, results in the weekend option having more total hours of control in the season – thus defeating a key part of Mohave's attempt at simplicity and reward for including weekend hours.

As an alternative to its initial RES TOU rates, Mohave is willing to offer shortened summer on-peak periods for both RES TOU optional rates (with and without weekends) in the summer, while maintaining the differential in total hours of control between the two options. This alternative rate design for the RES TOU rate options is summarized on MWS-Rebuttal Schedule 7 and developed on MWS-Rebuttal Schedule 6a. A summary of the proposed hours in each option is provided on MWS-Rebuttal Schedule 3.

As originally proposed, the summer peak period excluding weekends would be from 12PM to 9PM (9 hours) and the summer peak period including weekends would be from 2PM to 8:30 PM (6.5 hours). Both options would have approximately 2,350 peak hours per year (including winter). Mohave's rebuttal proposal is that the summer peak period excluding weekend would be from 12PM to 7:30PM (7.5 hours) and the summer peak period including weekends would be from 2PM to 7:30 PM (5.5 hours). Both options would have approximately 2,090 peak hours per year (including winter). Staff and Mohave agree with Mohave's originally proposed Winter hours.

No residential customer desiring to participate in the TOU rate is required to reduce weekend load. And, since the existing TOU rate has a summer peak period from 12PM to 9PM, any customer connecting to TOU before rates could be changed would have decreased hours of peak as compared to existing rates.

As was the case with all rates, the Residential TOU rates were modified to reflect the rebuttal change in base power cost and to total revenue requirement.

Q. How does Mohave's customer charge for its net metering customers relate to its time of use rates?

A. Under the net metering tariff approved by the Commission, the customer charge for net metering customers is the same as the customer charge for the applicable TOU rate for that class of customer. The Commission recognized that TOU and net metering customers require similar metering, meter reading, customer service, and billing services and cost Mohave more to service than standard customers. Therefore the customer charge for both, in a particular class of customers, should be generally be the same.

Q. Would the residential TOU and net metering rates be phased if the standard residential rates are phased?

A. Because of the costs associated with phasing in a relatively few customers, Mohave would prefer not to phase in the customer charges for TOU and net metering residential customers. These rates are optional and customers can chose to move to the standard rate if the difference in customer charge per month is an issue to them.

14. RESIDENTIAL EXPERIMENTAL DEMAND RATE

Q. What rate design does Mohave recommend for its proposed experimental residential demand rate?

A. Staff did not discuss this rate in direct testimony or provide suggested rate designs for review. Mohave believes the customer charges for the experimental residential demand rate and the RES TOU rate should be set at the same level since both rate classes, along with net metering customers, require additional metering, meter reading customer service, and billing expenses. Mohave proposes this level be set at $21.50 per month, but in any case, believes the level should be $5 greater than the approved customer charge for the standard residential rate.

The rebuttal rate design for net metering is shown on MWS-Rebuttal Schedule 6. The rebuttal rate design for residential demand is shown on MWS-Rebuttal Schedule 6b and summarized on MWS-Rebuttal Schedule 7.

As was the case with all rates, the Residential Demand rate was modified to reflect the Rebuttal base power cost and total revenue requirement.

15. SMALL COMMERCIAL RATES

Q. Does Mohave agree with Staff rate designs for the small commercial energy, small commercial TOU and small commercial net metering rates?

A. Mohave agrees with Staff that Mohave's "Small Commercial Energy and Small Commercial - Net Metering customer charges are based on residential charges." (Direct Testimony of Bentley Erdwurm, p. 10, lines 18-19). Therefore, Mohave continues to propose that the Small Commercial - Energy customer charge be the same as the customer charge for the RES TOU customers and that the Small Commercial – Energy net metering customer charge should be an additional $5 per month. The customer charge for Small Commercial – Demand TOU customers should also be $5 per month more than the customer charge for the standard Small Commercial – Demand customer. In other words, a $5 per month differential is appropriate for the additional costs associated with providing net metering and TOU service to members.

Q. Does Mohave agree with Staff rate designs for the small commercial demand rate?

A. In general, Mohave agrees with the Staff recommended rate designs. Mohave has proposed a small change in the bundled demand charges for all rates related to its rebasing of power cost. Mohave agrees with the Staff customer charge.

The rebuttal rate designs are shown on MWS-Rebuttal Schedule 6 and summarized on MWS-Rebuttal Schedule 7.

As was the case with all rates, Small Commercial rates were modified to reflect the Rebuttal base power cost and total revenue requirement.

16. IRRIGATION AND IRRIGATION TOU RATE

Q. Does Mohave agree with Staff rate designs for the Irrigation and IRR TOU rates?

A. In general, Mohave agrees with the Staff recommended rate designs. Mohave has proposed small changes in bundled demand charges related to rebasing of power cost. Mohave agrees with the Staff customer charge.

The rebuttal rate designs are shown on MWS-Rebuttal Schedule 6 and summarized on MWS-Rebuttal Schedule 7.

As was the case with all rates, Irrigation rates were modified to reflect the Rebuttal base power cost and total revenue requirement.

17. LARGE COMMERCIAL AND INDUSTRIAL RATE AND LC&I TIME OF USE RATE

Q. Does Mohave agree with Staff rate designs for the LC&I standard rate?

A. In general, Mohave agrees with the Staff recommended rate designs for the LC&I standard rate. Mohave has proposed a small change in the bundled demand charge related to its rebasing of power cost. And, as was the case with all rates, LC&I standard rates were modified to reflect the Rebuttal base power cost and total revenue requirement. Mohave agrees with the Staff customer charge.

Q. Does Mohave agree with Staff rate designs for the LC&I TOU rate?

A. No. Staff's recommended LC&I TOU rate, Mohave believes inadvertently, has the potential to send an incorrect price signal and allow the standard LC&I customers to dramatically reduce their electric costs without providing any cost savings to Mohave or any benefit from reductions in peak load. As a result, if Staff's rate design were adopted and a significant number of LC&I standard customers shifted to the TOU rate, Mohave's operating margins, TIER and DSC would all be negatively impacted. Total revenue Mohave and Staff have agreed should be recovered from Mohave's members would not be recovered, specifically due to under recovery from this rate class.

Q. Please explain.

A. While Staff deems Mohave's proposed LC&I TOU rate is appropriate for new customers (Direct Testimony of Bentley Erdwurm, p.4, line 24), Staff developed a different TOU rate design in an effort to limit the impact on the three existing LC&I TOU customers. Id., p.4, lines 25-26. As a result, a large number of existing standard LC&I customers could save money simply by moving to the Staff's recommended LC&I TOU rate. They would not be required to do anything to reduce on-peak usage to achieve savings. If these customers were to shift to the LC&I TOU, Mohave would lose approximately $1.8 million per year in revenue where the total rate increase being requested is just under $3 million.

Q. Why do the proposed LC&I TOU rates result in a 40% increase to the 3 existing LC&I TOU customers?

A. The primary reason for the large percentage increase to the three existing LC&I TOU customers is that the existing rate is not correctly designed. It allows customers to shift usage out of on-peak windows and eliminate paying for both power supply related demand costs, as well as any portion of Mohave's distribution wires service costs. The large percentage is not a reflection of the fact that the proposed rate is too high, but rather that the existing rate is poorly designed and therefore unacceptably low for these 3 customers.

Designing an optional rate available to existing customers must never happen in a vacuum. Each standard LC&I customer will have the option of selecting the proposed LC&I standard rate or the LC&I TOU rate. So the LC&I TOU rate must be designed to match the LC&I standard rate or customers can migrate to the TOU rate, do nothing to lower on-peak usage, and dramatically reduce the Cooperative's margins. This is particularly the case with this rate class, which makes up the Cooperative's largest customers.

<u>MWS-Rebuttal Schedule 9</u>, shows application of the Staff proposed rate to each existing LC&I customer with the assumption that 100% of each customer's NCP kW will become its on-peak kW under the LC&I TOU rate. Almost every customer would see a decrease – the total decrease is $1.8 million.

It is my understanding that Staff is in agreement with Mohave about this issue and that Staff has indicated their agreement that the originally suggested Staff LC&I TOU rate will need to be modified in some way to avoid the potential revenue impact I have described above.

I have reviewed a variety of rate design options to correct this situation without a large increase for existing LC&I TOU customers. No solution was found that both preserved the Staff-approved margins and reduced the percentage increase for the existing customers. In addition, Staff has agreed with Mohave that its proposed LC&I TOU rate is "reasonable for designing a new rate." (Direct Testimony of Bentley Erdwurm, p.4, line 24. Given the agreement expressed by Staff with the rate design proposed for new customers, therefore, I believe it would be a mistake to design a rate applicable to all LC&I customers driven by the negative impact it has on three customers with usage that is quite atypical of the customer group as a whole.

Q. Given the fact that Staff agrees that Mohave's proposed LC&I TOU rate is reasonable for new customers (Direct Testimony of Bentley Erdwurm, p.4, line 24), did the Cooperative consider requesting that the three existing customers be "grandfathered" and applying the proposed rate to new customers in the rate class?

A. Yes, but the Cooperative ultimately decided this was unfair to other members and is not proposing it as a part of its rebuttal rate designs. Mohave's COSS shows on Schedule G-2.1, the standard LC&I rate class under existing rates has a relative rate of return (RROR) of 10.47, while the LC&I TOU rate class under existing rates has a

RROR of -0.34. Mohave's residential rate class has a RROR of 0.20. RRORs greater than 1.0 provide a subsidy to other rate classes. RRORs under 1.0 receive a subsidy.

Mohave's other customer classes (including residential) with higher RRORs than LC&I TOU are, therefore, subsidizing existing LC&I TOU customers. Under Mohave's proposed rates, the LC&I RROR moves to 4.11, while the LC&I TOU RROR moves to 1.74.

Q. What types of customers are included in this rate class?

A. The existing customers have relatively high monthly NCP kW and quite low monthly CP kW. One customer in particular creates great rate design difficulty within the class. This customer is a commercial/industrial aggregate business. In 2010, the customer had total annual usage of 179,880 kWh. The sum of the customer's monthly NCP kW was 3,637 kW. This means the customer's annual load factor was only 7%. At the same time, the sum of this customer's on-peak kW <u>for the entire year</u> was 49.2 kW.

Mohave very much wants the existing LC&I TOU customers to be in its TOU rate. Since these customers have so little usage and can easily avoid peaks, the Cooperative wants to provide a pricing signal to do so. But Mohave cannot continue to provide these customers with a rate that also allows them to avoid recovery of Mohave's own cost of providing service. In his testimony on page 4, Mr. Erdwurm says that, "having an "on-peak" demand charge and an NCP demand charge is a more cost-based design that recognizes that "upstream" costs (incurred closer to power generation and further from the end-use customer) are more driven by the level of "on-peak demand" (system-wide coincident peaks) and "downstream" costs (incurred further from power generation and closer to the end-use customer) are more driven by NCP demand (localized non-coincident peaks)." I agree with his analysis. Later on the same page, he says, "the Staff proposal maintains this [Mohave's proposed NCP and CP demand rate] structure."

Q. What is Mohave's ultimate solution?

A. Mohave believes these customers should be billed under its rebuttal LC&I TOU rate structure. While this results in high percentage changes for these customers, and while Mohave is sensitive to the customer impact issue, such a percentage change is unavoidable without either placing Mohave's financial integrity at risk or without continuing to provide an unfair and unjustifiable subsidy to three customers at the expense of other customers, including residential customers. And, since Staff and Mohave are in agreement with the basic structure of the rate design, that design should be put into effect.

Q. Has Mohave considered phasing in the rate change to minimize customer impact?

A. Yes. While Mohave believes its proposed LC&I TOU rate is well structured and that existing LC&I TOU customers should ultimately move to this rate, Mohave is also sensitive to the customer impact issue raised by Staff and has developed a three phase approach for consideration.

Under this approach, all new LC&I TOU customers would be billed under Mohave's proposed LC&I rate. For the three existing customer only, a tariff would be approved that would be similar to Mohave's proposed Residential TOU rate phase in. That is, the customer would be billed under phase one on the effective date of the new rates, and then over the next two years commencing with November usage in 2013, move the customers to phase two, and then commencing with November usage in 2014, move the customers to phase three. In this manner the existing customers would be billed under the standard LC&I TOU rate with November usage of 2014.

The three phases would not be revenue neutral, and Mohave would not receive the full amount of the revenue requirement until phase three was in effect. But the amount of revenue difference between the phases is not significant. <u>MWS-Rebuttal Schedule 11</u> shows development of the three phases and the amount of revenue change between each phase and the existing rate, as well as the revenue change between one phase and another.

Q. Does Mohave believe that Staff's focus on the percentage change between the existing and proposed LC&I TOU rate is the correct metric to employ in evaluating these rates?

No. Mohave believes the focus on difference between existing LC&I TOU rate and proposed LC&I TOU rate is not the key factor in reviewing the proposed rate. The focus should instead be on whether the proposed LC&I TOU rate as compared to the proposed LC&I standard rate provides these customers an opportunity to continue to achieve significant savings by moving usage out of on-peak windows.

<u>MWS-Rebuttal Schedule 10</u> page 1 shows that under existing rates, existing LC&I TOU customers save $48,035 per year as compared to billing under the existing standard LC&I rate. Under Mohave's originally proposed LC&I TOU rate, the same customers would save $39,031 per year as compared to Mohave's originally proposed LC&I rate – still a significant savings. Under Staff's recommended LC&I TOU rate (see page 2 of the same report), the same customers will save $46,836 per year as compared to Staff's recommenced LC&I rate. Under Mohave's proposed rebuttal rates phase three (see page 5 of the same report), these customers would

have savings of $39,477 as compared to the proposed rebuttal LC&I standard rate – a strong pricing signal to adopt the TOU rate.

It should be noted that, as is the case under existing rates, each LC&I TOU customer can at any time move back to the standard LC&I rate. This means their potential billing increase is effectively capped at no more than what any other customer of their size and usage would see under the LC&I rate.

18. LIGHTING RATES

Q. Does Mohave agree with the Staff recommended lighting rates?

A. Just as Staff revised lighting rates primarily to account for Staff differences in base power cost and revenue requirement, Mohave's rebuttal rates have been modified for differences in rebuttal base power cost and revenue requirement.

19. GENERAL RATE DESIGN COMMENTS

Q. Do you have comments of a general nature related to rate designs to add?

A. Yes. It is important to note that Mohave's proposed rate designs were approved by its board of directors prior to being submitted to the Commission. This fact should be considered in three main areas.

> First, Mohave's board is democratically elected by cooperative members to represent the member-customers when making decisions, including decisions related to rate changes.
>
> Second, each board member lives in the area and is themselves a Mohave member who will pay the rates they approve.
>
> Third, should Mohave's members disagree with rate designs recommended by their board, they can influence change and/or their board member representative through the democratic process.

In addition, Mohave held a series of member meetings across its service area at the time rates were submitted to Staff. During those meetings, proposed rates were shown and discussed and opportunities were given to express objections. Mohave staff and board members were present to answer questions and to hear comments. No rate design objections were presented, including no objections to proposed customer charges.

Mohave's members have a great deal of opportunity to control the rate change process. While the Mohave Board or its members would prefer it if no rate increase were necessary, they also recognize that a small percentage increase coupled with much better rate designs are necessary and will serve Mohave and the members in the long term.

Mohave believes that as the elected representatives of the member-customers Mohave serves, the designs of the Mohave Board should be given weight and deference when it comes to the rate designs they propose to apply to themselves and the member-customers they represent.

Q. Does this conclude your testimony?

A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED OTHER REVENUE - CORRECTED

			Actual 2010		Adjusted 2010		Proposed 2010	
		Quantity	Rate	Revenue	Rate	Revenue	Rate	Revenue
As Filed								
451.00	Re-Establishment Fees	2,790	$ 25.00	$ 69,750.00	$ 25.00	$ 69,750.00	$ 40.00	$ 111,600.00
451.00	Establishment Fees	11,236	$ 25.00	280,900.00	$ 25.00	280,900.00	$ 40.00	$ 449,440.00
454.00	Pole Attachment Rental **	10,615	$ 20.99	222,768.04	$ 21.21	225,144.15	$ 21.21	$ 225,144.15
456.10	Returned Check Collection Charges	804	$ 15.00	12,060.00	$ 15.00	12,060.00	$ 25.00	$ 20,100.00
456.20	Meter Re-Read Charge	29	$ 5.00	145.00	$ 5.00	145.00	$ 25.00	$ 725.00
456.30	Meter Test Fees	0	$ 25.00	0.00	$ 25.00	0.00	$ 40.00	$ -
	Theft of Service			9,052.12		9,052.12		
	Tax Return Credit			9,883.17		9,883.17		
	Power Displacement Agreement *			117,546.00				
	Device Rental Agreement *			12,000.00				
	Disbursement Management Agm't *			15,000.00				
	Miscellaneous			(35.00)		(35.00)		
	Late Fees	3,769,168	0.0%	0.00	0.0%	0.00	1.5%	$ 56,537.52
	Total			$ 749,069.33		$ 606,899.44		$ 863,546.67
As Revised								
451.00	Establishment Regular Hours	13,326	$ 25.00	$ 333,150.00	$ 25.00	$ 333,150.00	$ 40.00	$ 533,040.00
451.00	Establishment After Hours	350	$ 50.00	17,500.00	$ 50.00	17,500.00	$ 60.00	$ 21,000.00
454.00	Pole Attachment Rental **	10,615	$ 20.99	222,768.04	$ 21.21	225,144.15	$ 21.21	$ 225,144.15
456.10	Returned Check Collection Charges	804	$ 15.00	12,060.00	$ 15.00	12,060.00	$ 25.00	$ 20,100.00
456.20	Meter Re-Read Charge	29	$ 5.00	145.00	$ 5.00	145.00	$ 25.00	$ 725.00
456.30	Meter Test Fees	0	$ 25.00	0.00	$ 25.00	0.00	$ 40.00	$ -
	Theft of Service			9,052.12		9,052.12		
	Tax Return Credit			9,883.17		9,883.17		
	Power Displacement Agreement *			117,546.00				
	Device Rental Agreement *			12,000.00				
	Disbursement Management Agm't *			15,000.00				
	Miscellaneous			(35.00)		(35.00)		
	Late Fees	3,721,333	0.0%	0.00	0.0%	$ -	1.5%	55,819.99
	Finance Charges on Delinquent Fees	763,535	0.0%	0.00	0.0%	$ -	1.5%	11,453.02
	Total			$ 749,069.33		$ 606,899.44		$ 867,282.16

Provided by Contract - will not continue in 2011 and beyond

***** Contract changed April 2010***

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MOHAVE ELECTRIC COOPERATIVE, INC.

STAFF'S ADJUSTED INCOME STATEMENT - MOHAVE'S REBUTTAL INCOME STATEMENT - INCLUDING RATE CASE EXPENSES
SUPPLEMENTAL DATA FOR THE YEAR ENDING DECEMBER 31, 2010

	Mohave Adjusted 12/31/2010 (a)	Staff Adjustments CSB-3 (b)	Staff Adjusted Test Year (c)	Staff Recommended Change (d)	Staff Recommended (e)
Operating Revenues					
1 Base Revenue (Remainder)	$ 56,732,893	$ 15,505,234	$ 72,238,127	$ 2,593,241	$ 74,831,368
2 Base Revenue (TPS Pur Pwr)	3,222,980		3,222,980		3,222,980
3 PCA	15,505,234	(15,505,234)	0		0
4 Other	606,899		606,899	312,468	919,367
5 Total	$ 76,068,006	$ 0	$ 76,068,006	$ 2,905,709	$ 78,973,715
6					
7 **Operating Expenses**					
8 Purchased Power	$ 61,802,677	$ (594,737)	$ 61,207,940	$	$ 61,207,940
9 SubTransmission O&M	169,400		169,400		169,400
10 Distribution-Operations	2,773,698		2,773,698		2,773,698
11 Distribution-Maintenance	1,194,657		1,194,657		1,194,657
12 Consumer Accounting	2,227,246		2,227,246		2,227,246
13 Customer Service	196,226		196,226		196,226
14 Sales	96,252		96,252		96,252
15 Administrative & General	4,756,463	562,035	5,318,498		5,318,498
16 Depreciation	2,239,666		2,239,666		2,239,666
17 Tax	0		0		0
18 Total	$ 75,456,285	$ (32,702)	$ 75,423,583	$ 0	$ 75,423,583
19					
20 Return	$ 611,721	$ 32,702	$ 644,423	$ 2,905,709	$ 3,550,132
21					
22 **Interest & Other Deductions**					
23 Interest L-T Debt	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308
24 Amortize RUS Gain	0		0		0
25 Interest-Other	142,396		142,396		142,396
26 Other Deductions	17,024		17,024		17,024
27 Total	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728
28					
29 Operating Margin	$ (1,709,007)	$ 32,702	$ (1,676,305)	$ 2,905,709	$ 1,229,404
30					
31 **Non-Operating Margins**					
32 Interest Income	$ 410,049	$	$ 410,049	$	$ 410,049
33 Gain(Loss) Equity Investments	110,369		110,369		110,369
34 Other Margins	(32,307)		(32,307)		(32,307)
35 G&T Capital Credits	3,509,969		3,509,969		3,509,969
36 Other Capital Credits	107,687		107,687		107,687
37 Total	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767
38					
39 Net Margins	$ 2,396,760	$ 32,702	$ 2,429,462	$ 2,905,709	$ 5,335,171
40 Rate Change					3.820%
41 Operating TIER					1.57

	Mohave Adjusted 12/31/2010 (a)	Mohave Rebuttal Adjustments (b)	Mohave Rebuttal Adj TY (c)	Mohave Rebuttal Recommended Change (d)	Mohave Rebuttal Recommended (e)
Operating Revenues					
1 Base Revenue (Remainder)	$ 56,732,893	$ 15,505,234	$ 72,238,127	$ 2,745,326	$ 74,983,453
2 Base Revenue (TPS Pur Pwr)	3,222,980		3,222,980		3,222,980
3 PCA	15,505,234	(15,505,234)	0		0
4 Other	606,899		606,899	260,383	867,282
5 Total	$ 76,068,006	$ 0	$ 76,068,006	$ 3,005,709	$ 79,073,715
6					
7 **Operating Expenses**					
8 Purchased Power	$ 61,802,677	$ (32,702)	$ 61,769,975	$	$ 61,769,975
9 SubTransmission O&M	169,400		169,400		169,400
10 Distribution-Operations	2,773,698		2,773,698		2,773,698
11 Distribution-Maintenance	1,194,657		1,194,657		1,194,657
12 Consumer Accounting	2,227,246		2,227,246		2,227,246
13 Customer Service	196,226		196,226		196,226
14 Sales	96,252		96,252		96,252
15 Administrative & General	4,756,463	100,000	4,856,463		4,856,463
16 Depreciation	2,239,666		2,239,666		2,239,666
17 Tax	0		0		0
18 Total	$ 75,456,285	$ 67,298	$ 75,523,583	$ 0	$ 75,523,583
19					
20 Return	$ 611,721	$ (67,298)	$ 544,423	$ 3,005,709	$ 3,550,132
21					
22 **Interest & Other Deductions**					
23 Interest L-T Debt	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308
24 Amortize RUS Gain	0		0		0
25 Interest-Other	142,396		142,396		142,396
26 Other Deductions	17,024		17,024		17,024
27 Total	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728
28					
29 Operating Margin	$ (1,709,007)	$ (67,298)	$ (1,776,305)	$ 3,005,709	$ 1,229,404
30					
31 **Non-Operating Margins**					
32 Interest Income	$ 410,049	$	$ 410,049	$	$ 410,049
33 Gain(Loss) Equity Investments	110,369		110,369		110,369
34 Other Margins	(32,307)		(32,307)		(32,307)
35 G&T Capital Credits	3,509,969		3,509,969		3,509,969
36 Other Capital Credits	107,687		107,687		107,687
37 Total	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767
38					
39 Net Margins	$ 2,396,760	$ (67,298)	$ 2,329,462	$ 3,005,709	$ 5,335,171
40 Rate Change					3.951%
41 Operating TIER					1.57

MWS-Rebuttal Schedule A-1

MOHAVE ELECTRIC COOPERATIVE, INC.

RATE CASE EXPENSE

Rate Case Expense	$ 400,000.00
Number of Years to Amortize	4
Annual Expense	$ 100,000.00
Test Year Amount	0.00
Adjustment	$ 100,000.00

MOHAVE ELECTRIC COOPERATIVE, INC.
Actual Expenses and Projected Expenses

Project-To-Date as of: 31-Jan-12

Components	2010 Costs	2011 Costs	2012 Costs	Total Costs
Engineering & Consulting	44,526.70	177,486.36	11,180.00	233,193.06
Publication & Computer Programming	-	24,363.16		24,363.16
Legal Costs	-	83,534.22		83,534.22
Estimated Add'l Recoverable Cost			58,909.56	58,909.56
Totals	44,526.70	285,383.74	70,089.56	400,000.00

Work Order #__________

AGREEMENT FOR CONSTRUCTING ELECTRIC FACILITIES

THIS AGREEMENT, made and entered into in duplicate on this ______________ day of ______________, 20___ by and between MOHAVE ELECTRIC COOPERATIVE, INC., an Arizona Corporation, party of the first part, (hereinafter referred to as "Mohave") and

a corporation, partnership, or individual, party of the second part (hereinafter referred to as the "Consumer").

WITNESSETH:

WHEREAS, Mohave is a corporation engaged in the sale and distribution of electrical energy in portions of Mohave, Yavapai, and Coconino Counties, Arizona; and

WHEREAS, the Consumer is subdividing and developing a portion of that area and it is to be served with electricity by virtue of an electric system; and

WHEREAS, it is desired by the parties hereto to enter into an agreement whereby Mohave will construct and operate such a system to service said area:

NOW THEREFORE *for and in consideration of mutual covenants and agreements* hereinafter set forth, it is agreed as follows:

Mohave agrees to construct or cause to be constructed and to maintain and operate an electric system in the above-described area in accordance with existing specifications and estimates upon the following terms and conditions:

SECTION I. TERMS OF CONSTRUCTION

1. This estimated construction cost is valid for 60 (sixty) calendar days from ____________. The full estimated cost of construction must be paid, this agreement must be executed, and Mohave's construction must be started within that 60 (sixty) days, or this agreement may be declared null and void at the option of Mohave.

2. The Consumer will advance Mohave the full estimated cost of construction, $______, in accordance with Mohave's construction practices.

At the time construction is finished, Mohave will:

a. Return to the Consumer any advance in excess of actual construction cost, or

b. Bill the Consumer that amount which is in excess of the estimated construction cost.

3. If an underground electric line extension is requested, then the Consumer will provide all necessary conduit, trenching, backfill, vaults, and three phase transformer pads as required by Mohave without cost to Mohave. All primary and secondary conduits are to be inspected by Mohave prior to backfill, and shall be 3" Schedule 40 electrical grade PVC conduit(s).

SECTION II. REFUNDING

1. Upon completion of construction, the estimated cost on this agreement will be adjusted to reflect the actual cost of construction.

2. The term of this agreement is five (5) years. Refunds will be calculated and made each six (6) months during the term of this agreement. Any advance funds remaining un-refunded at the end of the five (5) year term will revert to Mohave as a direct contribution in aid of construction

3. Mohave will refund a portion of the cost of construction to the Consumer for each electrical consumer attached to the electric system during the term of this agreement upon the following terms and conditions:

   a. The connection must be a permanent member/consumer as defined by Mohave.

   b. In no case shall refunds exceed the Consumer's aid-to-construction.

4. The Consumer will furnish to Mohave names and addresses of residents as they occupy individual lots during any six (6) month period for the purpose of refunds.

SECTION III. OTHER CONDITIONS

1. This estimate is based on information supplied to Mohave by the Consumer. Should the plans, specifications, and/or details supplied to Mohave change, Mohave has the option of rendering this agreement null and void, or requiring the Consumer to make the necessary corrections at his expense.

2. All easements or rights-of-way and surveying required by Mohave will be furnished to Mohave without cost. These will be furnished in a manner and form approved by Mohave, and must be satisfactory to Mohave.

3. If an underground line extension is requested, then a detailed, referenced as-built plan of the conduit system shall be provided to Mohave upon completion of the conduit installation.

4. All construction will become the property of Mohave and will be owned, operated and maintained by Mohave, except the individual Consumer's wiring, disconnect breakers or switches, and facilities on the Consumer's premises.

5. In the event this construction agreement is cancelled by the Consumer, an amount equal to 15% of the Consumer's advance shall be withheld from the Consumer's advance as a Cancellation Fee. This Cancellation Fee is in addition to any direct costs, including overheads, that may have already been incurred on this construction agreement at the time of cancellation by the Consumer. This fee does not include the purchase cost of Special Equipment (special order materials) purchased for the construction agreement; the purchase cost of Said Special Equipment (including tax and shipping) shall also be deducted from the Consumer's advance, and Said Special Equipment shall become the property of the Consumer.

SECTION IV. EXECUTION OF AGREEMENT

The parties hereto have caused this agreement to be executed by their duly authorized officers all on the day and year written below.

Consumer Signatures

By________________________________
Consumer Signature

By________________________________
Consumer Printed Name

By________________________________
Attestor Signature

By________________________________
Attestor Printed Name

Date______________________________

Cooperative Signatures

By________________________________
Mohave Electric Cooperative, Inc.

By________________________________
Attestor

Date______________________________

Revised 07/09

MOHAVE ELECTRIC COOPERATIVE, INC.

RESIDENTIAL TIME OF USE ON PEAK OPTIONS

	EXISTING RATE	MOHAVE PROPOSED		STAFF PROPOSED		MOHAVE REBUTTAL	
		OPTION 1 *	OPTION 2 *	OPTION 1 *	OPTION 2 *	OPTION 1 *	OPTION 2 *
SUMMER							
Apr 16 - Oct 15	12 pm - 9 pm	12 pm - 9 pm	2 pm - 8:30 pm	1 pm - 7:30 pm	1 pm - 7:30 pm	12 pm - 7:30 pm	2 pm - 7:30 pm
Block Length	9	9	6.5	6.5	6.5	7.5	5.5
WINTER							
Oct 16 - Apr 15	6 am - 10 am	6 am - 10 am	6:30 am - 9:30 am	6 am - 10 am	6:30 am - 9:30 am	6 am - 10 am	6:30 am - 9:30 am
	5 pm - 10 pm	5 pm - 10 pm	5:30 pm - 9:00 pm	5 pm - 10 pm	5:30 pm - 9:00 pm	5 pm - 10 pm	5:30 pm - 9:00 pm
Total Block Length	9	9	6.5	9	6.5	9	6.5
Total Annual Hours	2,349	2,349	2,373	2,019	2,373	2,085	2,097

*** OPTION 1 EXCLUDES WEEKENDS**
*** OPTION 2 INCLUDES WEEKENDS**

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED PPCA BASE COST - 2010 DATA

	Mohave Original Filing			Staff Recommendation			Mohave Rebuttal		
	Adjusted 2010	Proposed 2010	Difference	Adjusted 2010	Proposed 2010	Difference	Adjusted 2010	Proposed 2010	Difference
Total kWh Sales	655,743,735	655,743,735	0	655,743,735	655,743,735	0	655,743,735	655,743,735	0
Less Lighting kWh Sales	1,100,103		(1,100,103)	1,100,103		(1,100,103)	1,100,103		(1,100,103)
Jurisdictional kWh Sales	654,643,632	655,743,735	1,100,103	654,643,632	655,743,735	1,100,103	654,643,632	655,743,735	1,100,103
Jurisdictional Purchased Power	58,579,697	58,579,697	0	58,579,697	58,579,697	0	58,579,697	58,579,697	0
Remove Consultants & Attorney			0		-571,723	(571,723)		-32,702	(32,702)
Remove Fuel Bank Consulting					-23,015				
Remove TPS Margins (PP already removed)					-475,687				
Purchased Power	58,579,697	58,579,697	0	58,579,697	57,509,272	(1,070,424)	58,579,697	58,546,995	(32,702)
Power Cost per kWh Sold	0.089483	0.089333	(0.000150)	0.089483	0.087701	(0.001782)	0.089483	0.089283	(0.000200)
Authorized Base Cost	0.065798	**0.091183**	0.025385	0.065798	**0.087701**	0.021903	0.065798	**0.089283**	0.023485
Average PPCA Factor	0.023685	(0.001850)	(0.025535)	0.023685	0.000000	(0.023685)	0.023685	0.000000	(0.023685)

Adjusted 2010 Power Cost on Supplemental Schedule F-7.0
Adjusted 2010 kWh Sales on Supplemental Schedule F-2.0
Note: PPCA to be charged on lighting under new rates

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES

			kWh			Mohave Proposed Rates			Staff Proposed Rates			Mohave Rebuttal		
					Adjusted	Proposed	Change		Proposed	Change		Proposed	Change	
		Cust	Total	Avg Mn	2010	2010	$	%	2010	$	%	2010	$	%
Residential		34,875	364,970,959	872	42,986,712	44,735,329	1,748,617	4.07%	44,625,240	1,638,528	3.81%	44,739,019	1,752,307	4.08%
Irrigation Time of Use		12	1,730,345	12,016	166,306	168,026	1,720	1.03%	167,368	1,062	0.64%	168,033	1,727	1.04%
Irrigation Pumping		11	2,572,007	19,485	302,194	309,962	7,768	2.57%	308,398	6,204	2.05%	309,995	7,801	2.58%
Subtotal Irrigation		23	4,302,352	15,588	468,500	477,988	9,488	2.03%	475,766	7,266	1.55%	478,028	9,528	2.03%
Small Comm Energy		3,201	42,164,591	1,098	4,900,351	5,177,391	277,040	5.65%	5,182,804	282,453	5.76%	5,178,524	278,173	5.68%
Small Comm Demand		529	70,626,268	11,126	7,389,210	7,729,118	339,908	4.60%	7,703,730	314,520	4.26%	7,730,537	341,327	4.62%
Small Comm TOU		8	1,020,044	10,625	96,177	100,936	4,759	4.95%	101,248	5,071	5.27%	100,956	4,779	4.97%
Subtotal Small Comm		3,738	113,810,903	2,537	12,385,738	13,007,445	621,707	5.02%	12,987,782	602,044	4.86%	13,010,017	624,279	5.04%
Large Comm & Industrial		118	170,994,538	4,495,062	15,775,430	16,108,634	333,204	2.11%	16,103,767	328,337	2.08%	16,110,076	334,646	2.12%
LC&I TOU		3	564,880	15,691	48,035	67,443	19,408	40.40%	60,366	12,331	25.67%	67,524	19,489	40.57%
Lighting Devices	*	1,151	1,100,103	80	98,025	103,184	5,159	5.26%	103,595	5,570	5.68%	103,011	4,986	5.09%
Resale	*	1	46,862,961	3,905,247	3,698,667	3,698,667	0	0.00%	3,698,667	0	0.00%	3,698,667	0	0.00%
Total Energy Sales	*	38,757	702,606,696	1,511	75,461,107	78,198,690	2,737,583	3.63%	78,055,183	2,594,076	3.44%	78,206,342	2,745,235	3.64%
Other Revenue					606,899	863,547	256,647	42.29%	919,367	312,468	51.49%	867,282	260,383	42.90%
Total Revenue					76,068,007	79,062,237	2,994,230	3.94%	78,974,550	2,906,543	3.82%	79,073,624	3,005,617	3.95%
													3,005,709	

** Total Customers excludes Lighting Devices and Resale*

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

		Billing	Proposed Rate			Proposed Revenue		
		Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE								
Residential								
Service Charge (12 Month Sum)		417,302	0.00	16.50	16.50	0	6,885,483	6,885,483
Energy Charge per kWh								
First	200 kWh per month	75,441,637	0.081047	0.008929	0.089976	6,114,318	673,618	6,787,937
Next	200 kWh per month	62,783,417	0.081047	0.008929	0.089976	5,088,408	560,593	5,649,001
Next	200 kWh per month	50,237,165	0.094547	0.010429	0.104976	4,749,773	523,923	5,273,697
Next	200 kWh per month	39,197,460	0.094547	0.010429	0.104976	3,706,002	408,790	4,114,793
Next	200 kWh per month	30,436,462	0.094547	0.010429	0.104976	2,877,676	317,422	3,195,098
Over	1,000 kWh per month	106,015,612	0.108047	0.011929	0.119976	11,454,669	1,264,660	12,719,329
Base Revenue		364,111,753				33,990,846	10,634,489	44,625,338
PPCA Revenue						0	0	0
Total Revenue						33,990,846	10,634,489	44,625,338
Residential - Seasonal								
Service Charge (12 Month Sum)		11	0.00	16.50	16.50	0	182	182
Energy Charge per kWh								
First	200 kWh per month	201	0.081047	0.008929	0.089976	16	2	18
Next	200 kWh per month	200	0.081047	0.008929	0.089976	16	2	18
Next	200 kWh per month	148	0.094547	0.010429	0.104976	14	2	16
Next	200 kWh per month	0	0.094547	0.010429	0.104976	0	0	0
Next	200 kWh per month	0	0.094547	0.010429	0.104976	0	0	0
Over	1,000 kWh per month	0	0.108047	0.011929	0.119976	0	0	0
Base Revenue		549				46	188	234
PPCA Revenue						0	0	0
Total Revenue						46	188	234
Residential - Net Metering								
Service Charge (12 Month Sum)		863	0.00	21.50	21.50	0	18,555	18,555
Energy Charge per kWh								
First	200 kWh per month	114,805	0.081047	0.008929	0.089976	9,305	1,025	10,330
Next	200 kWh per month	97,201	0.081047	0.008929	0.089976	7,878	868	8,746
Next	200 kWh per month	79,816	0.094547	0.010429	0.104976	7,546	832	8,379
Next	200 kWh per month	63,706	0.094547	0.010429	0.104976	6,023	664	6,688
Next	200 kWh per month	49,825	0.094547	0.010429	0.104976	4,711	520	5,230
Over	1,000 kWh per month	234,706	0.108047	0.011929	0.119976	25,359	2,800	28,159
Base Revenue		640,060				60,822	25,264	86,087
PPCA Revenue						0	0	0
Total Revenue						60,822	25,264	86,087

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE (Continued)							
Res - Gov							
Service Charge (12 Month Sum)	318	0.00	16.50	16.50	0	5,247	5,247
Energy Charge per kWh							
First 200 kWh per month	60,246	0.081047	0.008929	0.089976	4,883	538	5,421
Next 200 kWh per month	44,692	0.081047	0.008929	0.089976	3,622	399	4,021
Next 200 kWh per month	28,446	0.094547	0.010429	0.104976	2,689	297	2,986
Next 200 kWh per month	20,173	0.094547	0.010429	0.104976	1,907	210	2,118
Next 200 kWh per month	15,693	0.094547	0.010429	0.104976	1,484	164	1,647
Over 1,000 kWh per month	49,347	0.108047	0.011929	0.119976	5,332	589	5,920
Base Revenue	218,597				19,917	7,444	27,360
PPCA Revenue					0	0	0
Total Revenue					19,917	7,444	27,360
Base Revenue	364,970,959				34,071,631	10,667,385	44,739,019
PPCA Revenue					0	0	0
Total Revenue					34,071,631	10,667,385	44,739,019
2. IRRIGATION SERVICE							
Irrigation Time of Use							
Service Charge (12 Month Sum)	144	0.00	66.91	66.91	0	9,635	9,635
On-Peak Demand	2,234.49	8.90	0.00	8.90	19,887	0	19,887
NCP Demand	8,466.81	0.00	1.60	1.60	0	13,547	13,547
Energy Charge per kWh	1,730,345	0.072135	0.000084	0.072219	124,818	145	124,964
Base Revenue					144,705	23,327	168,033
PPCA Revenue					0	0	0
Total Revenue					144,705	23,327	168,033
Irrigation Pumping							
Service Charge (12 Month Sum)	132	0.00	61.76	61.76	0	8,152	8,152
NCP Demand	12,025.74	5.90	1.60	7.50	70,952	19,241	90,193
Energy Charge per kWh	2,572,007	0.072135	0.010155	0.082290	185,532	26,119	211,650
Base Revenue					256,484	53,512	309,995
PPCA Revenue					0	0	0
Total Revenue					256,484	53,512	309,995
Base Revenue	4,302,352				401,189	76,839	478,028
PPCA Revenue					0	0	0
Total Revenue					401,189	76,839	478,028

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE							
Sm Comm Demand - Net Metering							
Service Charge (12 Month Sum)	5	0.00	41.03	41.03	0	205	205
NCP Demand > 3 kW	73.68	6.31	4.61	10.92	465	340	805
Energy Charge per kWh	24,280	0.073000	0.000191	0.073191	1,772	5	1,777
Base Revenue					2,237	550	2,787
PPCA Revenue					0	0	0
Total Revenue					2,237	550	2,787
Small Commercial Demand							
Service Charge (12 Month Sum)	5,552	0.00	36.03	36.03	0	200,039	200,039
NCP Demand > 3 kW	187,060.45	6.31	4.61	10.92	1,180,351	862,349	2,042,700
Energy Charge per kWh	63,019,478	0.073000	0.000191	0.073191	4,600,422	12,037	4,612,459
Base Revenue					5,780,773	1,074,425	6,855,198
PPCA Revenue					0	0	0
Total Revenue					5,780,773	1,074,425	6,855,198
Small Commercial Energy							
Service Charge (12 Month Sum)	35,164	0.00	21.50	21.50	0	756,026	756,026
Energy Charge per kWh	38,541,431	0.088094	0.015129	0.103223	3,395,269	583,093	3,978,362
Base Revenue					3,395,269	1,339,119	4,734,388
PPCA Revenue					0	0	0
Total Revenue					3,395,269	1,339,119	4,734,388
Small Commercial - Net Metering							
Service Charge (12 Month Sum)	49	0.00	26.50	26.50	0	1,299	1,299
Energy Charge per kWh	64,010	0.088094	0.013125	0.101219	5,639	840	6,479
Base Revenue					5,639	2,139	7,778
PPCA Revenue					0	0	0
Total Revenue					5,639	2,139	7,778
Small Commercial TOU							
Service Charge (12 Month Sum)	91	0.00	41.03	41.03	0	3,734	3,734
On-Peak Demand	1,430.12	15.00	0.00	15.00	21,452	0	21,452
NCP kW	3,175.62	0.00	4.61	4.61	0	14,640	14,640
Energy Charge per kWh	1,020,044	0.045185	0.014744	0.059929	46,091	15,040	61,130
Base Revenue					67,543	33,414	100,956
PPCA Revenue					0	0	0
Total Revenue					67,543	33,414	100,956
SC Energy Gov							
Service Charge (12 Month Sum)	3,208	0.00	21.50	21.50	0	68,972	68,972
Energy Charge per kWh	3,559,150	0.088094	0.015129	0.103223	313,540	53,846	367,386
Base Revenue					313,540	122,818	436,358
PPCA Revenue					0	0	0
Total Revenue					313,540	122,818	436,358

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE (Continued)							
SC Demand Gov							
Service Charge (12 Month Sum)	784	0.00	36.03	36.03	0	28,248	28,248
NCP Demand > 3 kW	26,495.68	6.31	4.61	10.92	167,188	122,145	289,333
Energy Charge per kWh	7,582,510	0.073000	0.000191	0.073191	553,523	1,448	554,971
Base Revenue					720,711	151,841	872,552
PPCA Revenue					0	0	0
Total Revenue					720,711	151,841	872,552
Base Revenue	113,810,903				10,285,712	2,724,306	13,010,017
PPCA Revenue					0	0	0
Total Revenue					10,285,712	2,724,306	13,010,017
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE							
Large C&I Secondary							
Service Charge (12 Month Sum)	983	0.00	175.00	175.00	0	172,025	172,025
NCP Demand	189,369.16	7.76	3.08	10.84	1,469,505	583,257	2,052,762
Energy Charge per kWh	76,311,058	0.064184	0.006000	0.070184	4,897,949	457,866	5,355,815
Base Revenue					6,367,454	1,213,148	7,580,602
PPCA Revenue					0	0	0
Total Revenue					6,367,454	1,213,148	7,580,602
Large C&I Primary							
Service Charge (12 Month Sum)	36	0.00	175.00	175.00	0	6,300	6,300
NCP Demand	17,172.00	7.76	3.08	10.84	133,255	52,890	186,144
Energy Charge per kWh	8,497,320	0.064184	0.006000	0.070184	545,392	50,984	596,376
Primary Discount on Demand & Energy		-1.00%	-1.00%	-1.00%	(6,786)	(1,039)	(7,825)
Base Revenue					671,861	109,135	780,995
PPCA Revenue					0	0	0
Total Revenue					671,861	109,135	780,995

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
Large C&I TOU							
Service Charge (12 Month Sum)	31	0.00	180.00	180.00	0	5,580	5,580
On-Peak Demand	690.80	23.00	0.00	23.00	15,888	0	15,888
NCP kW	5,713.20	0.00	3.08	3.08	0	17,597	17,597
Energy Charge per kWh	564,880	0.045261	0.005120	0.050381	25,567	2,892	28,459
Base Revenue					41,455	26,069	67,524
PPCA Revenue					0	0	0
Total Revenue					41,455	26,069	67,524
Large C&I GOV							
Service Charge (12 Month Sum)	362	0.00	175.00	175.00	0	63,350	63,350
NCP Demand	64,343.36	7.76	3.08	10.84	499,304	198,178	697,482
Energy Charge per kWh	17,180,160	0.064184	0.006000	0.070184	1,102,691	103,081	1,205,772
Base Revenue					1,601,995	364,609	1,966,604
PPCA Revenue					0	0	0
Total Revenue					1,601,995	364,609	1,966,604
LC&I Trans (Current TOU) *Billed at Subtransmission Delivery Level*							
Service Charge (12 Month Sum)	12	0.00	175.00	175.00	0	2,100	2,100
NCP kW	53,106.00	7.76	3.08	10.84	412,103	163,566	575,669
Energy Charge per kWh	30,204,000	0.064184	0.006000	0.070184	1,938,614	181,224	2,119,838
Subtransmission Discount on Demand & Energy		-7.50%	-7.50%	-7.50%	(176,304)	(25,859)	(202,163)
Base Revenue					2,174,413	321,031	2,495,444
PPCA Revenue					0	0	0
Total Revenue					2,174,413	321,031	2,495,444

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

		Billing	Proposed Rate			Proposed Revenue		
		Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)								
LP Substation	***Billed at Substation Delivery Level***							
Service Charge (12 Month Sum)		24	0.00	175.00	175.00	0	4,200	4,200
NCP kW		67,500.00	7.76	3.08	10.84	523,800	207,900	731,700
Energy Charge per kWh		38,802,000	0.064184	0.006000	0.070184	2,490,468	232,812	2,723,280
Substation Discount on Demand & Energy			-5.00%	-5.00%	-5.00%	(150,713)	(22,036)	(172,749)
Base Revenue						2,863,555	422,876	3,286,431
PPCA Revenue						0	0	0
Total Revenue						2,863,555	422,876	3,286,431
Base Revenue		171,559,418				13,720,733	2,456,868	16,177,600
PPCA Revenue						0	0	0
Total Revenue						13,720,733	2,456,868	16,177,600
5. LIGHTING SERVICE								
175 W MVL	102 kWh per month	6,039	6.19	0.94	7.13	37,381	5,677	43,058
100 W HPS	51 kWh per month	2,594	3.09	5.22	8.31	8,015	13,541	21,556
175 W MVL CO	101 kWh per month	320	6.13	0.49	6.62	1,962	157	2,118
100 W HPS CO	51 kWh per month	3,644	3.09	2.26	5.35	11,260	8,235	19,495
250 W HPS	130 kWh per month	1,211	7.89	5.97	13.86	9,555	7,230	16,784
Base Revenue		13,808				68,173	34,840	103,011
PPCA Revenue						0	0	0
Total Revenue						68,173	34,840	103,011
kWh		1,100,103						
6. RESALE REVENUE								
Base Revenue						3,222,980	475,687	3,698,667
PPCA Revenue						0	0	0
Total Revenue		46,862,961				3,222,980	475,687	3,698,667

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES - PHASE THREE

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
7. TOTAL REVENUE							
Base Revenue	702,606,696				61,770,418	16,435,925	78,206,342
PPCA Revenue					0	0	0
Other Revenue					0	863,547	863,547
Total					61,770,418	17,299,472	79,069,889

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL TIME OF USE RATES - 2010 DATA

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE							
Proposed Residential Rate							
Service Charge (12 Month Sum)	417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First 400 kWh per month	138,330,393	0.081047	0.008929	0.089976	11,211,263	1,235,152	12,446,415
Next 600 kWh per month	119,935,547	0.094547	0.010429	0.104976	11,339,546	1,250,808	12,590,354
Over 1,000 kWh per month	106,705,019	0.108047	0.011929	0.119976	11,529,157	1,272,884	12,802,041
Total							
Base Revenue	364,970,959				34,079,966	10,649,756	44,729,722
PPCA Revenue					0	0	0
Total Revenue					34,079,966	10,649,756	44,729,722

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL TIME OF USE RATES - 2010 DATA

			Billing	Proposed Rate			Proposed Revenue		
			Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Time of Use - Including Weekends On-peak									
Service Charge (12 Month Sum)			417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Desired Discount	**2.5%**	**Applied to Power Supply**							
Calculated Discount on total Energy Charges				**2.26%**					
Estimated On Peak kWh									
First	400	kWh per month	34,582,598	0.188708	0.008929	0.197637	6,526,013	308,788	6,834,801
Next	600	kWh per month	29,983,887	0.201870	0.010429	0.212299	6,052,847	312,702	6,365,549
Over	1,000	kWh per month	26,676,255	0.215033	0.011929	0.226962	5,736,275	318,221	6,054,496
Total			91,242,740						
Estimated Off Peak kWh									
First	400	kWh per month	103,747,795	0.045471	0.008929	0.054400	4,717,516	926,364	5,643,880
Next	600	kWh per month	89,951,660	0.058633	0.010429	0.069062	5,274,136	938,106	6,212,242
Over	1,000	kWh per month	80,028,764	0.071796	0.011929	0.083725	5,745,745	954,663	6,700,408
Total			273,728,219						
Base Revenue			364,970,959				34,052,532	12,737,911	46,790,443
PPCA Revenue							0	0	0
Total Revenue							34,052,532	12,737,911	46,790,443
Proposed Residential Time of Use - Excluding Weekends On-Peak									
Service Charge (12 Month Sum)			417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Assumed Off Peak kWh %		**75%**							
Estimated On Peak kWh									
First	400	kWh per month	34,582,598	0.193547	0.008929	0.202476	6,693,344	308,788	7,002,132
Next	600	kWh per month	29,983,887	0.207047	0.010429	0.217476	6,208,062	312,702	6,520,764
Over	1,000	kWh per month	26,676,255	0.220547	0.011929	0.232476	5,883,357	318,221	6,201,578
Total			91,242,740						
Estimated Off Peak kWh									
First	400	kWh per month	103,747,795	0.046637	0.008929	0.055566	4,838,444	926,364	5,764,808
Next	600	kWh per month	89,951,660	0.060137	0.010429	0.070566	5,409,387	938,106	6,347,493
Over	1,000	kWh per month	80,028,764	0.073637	0.011929	0.085566	5,893,046	954,663	6,847,709
Total			273,728,219						
Base Revenue			364,970,959				34,925,640	12,737,911	47,663,551
PPCA Revenue							0	0	0
Total Revenue							34,925,640	12,737,911	47,663,551

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL DEMAND RATES - 2010 DATA

1. RESIDENTIAL SERVICE

			Billing Units	Proposed Rate			Proposed Revenue		
				Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Rate									
Service Charge (12 Month Sum)			417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First	400	kWh per month	138,330,393	0.081047	0.008929	0.089976	11,211,263	1,235,152	12,446,415
Next	600	kWh per month	119,935,547	0.094547	0.010429	0.104976	11,339,546	1,250,808	12,590,354
Over	1,000	kWh per month	106,705,019	0.108047	0.011929	0.119976	11,529,157	1,272,884	12,802,041
Total									
Base Revenue			364,970,959				34,079,966	10,649,756	44,729,722
PPCA Revenue							0	0	0
Total Revenue							34,079,966	10,649,756	44,729,722

			Billing Units	Proposed Rate			Proposed Revenue		
				Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Demand Rate									
Service Charge (12 Month Sum)			417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Demand Charge	Assumed	3.00	1,252,893	8.00	0.50	8.50	10,023,144	626,447	10,649,591
First	400	kWh per month	138,330,393	0.053584	0.007204	0.060788	7,412,296	996,532	8,408,828
Next	600	kWh per month	119,935,547	0.067084	0.008704	0.075788	8,045,756	1,043,919	9,089,675
Over	1,000	kWh per month	106,705,019	0.080584	0.010204	0.090788	8,598,717	1,088,818	9,687,535
Total			364,970,959						
Base Revenue							34,079,913	12,734,783	46,814,696
PPCA Revenue							0	0	0
Total Revenue							34,079,913	12,734,783	46,814,696

MOHAVE ELECTRIC COOPERATIVE, INC.
SUMMARY OF RATES

	Existing Rate	Mohave Prop Rate	Staff Prop Rate	Mohave Rebuttal Rate Phase 1	Mohave Rebuttal Rate Phase 2	Mohave Rebuttal Rate Phase 3
Power Cost, per kWh Sold	$0.089483	$0.089333	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Base Cost, per kWh Sold	$0.065798	$0.091183	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Factor, per kWh	$0.023685	($0.001850)	$0.000000	$0.000000	$0.000000	$0.000000
Residential Service						
Service Charge, per month	$9.50	$16.50	$12.00	$12.00	$14.25	$16.50
First 400 kWh per month	$0.083190	$0.096373	$0.094823	$0.095136	$0.092556	$0.089976
Next 600 kWh per month	$0.083190	$0.106373	$0.109823	$0.110136	$0.107556	$0.104976
Over 1,000 kWh per month	$0.083190	$0.116373	$0.124823	$0.125136	$0.122556	$0.119976
Optional Res Time of Use - Excludes Weekends						
Service Charge, per month	$15.00	$21.50	$15.00			$21.50
On-Peak Energy Charge, per kWh						
First 400 kWh per month	$0.149500	$0.208316				$0.202486
Next 600 kWh per month	$0.149500	$0.218316				$0.217486
Over 1,000 kWh per month	$0.149500	$0.228316				$0.232486
Off-Peak Energy Charge, per kWh						
First 400 kWh per month	$0.052000	$0.058316				$0.055576
Next 600 kWh per month	$0.052000	$0.068316				$0.070576
Over 1,000 kWh per month	$0.052000	$0.078316				$0.085576
Optional Res Time of Use - Includes Weekends						
Discount on all energy charges excluding PPCA		2.25%	2.25%			2.25%
Experimental Residential Demand Service						
Service Charge, per month	$13.50	$21.50				$21.50
Demand Charge, per NCP kW	$7.50	$8.50				$8.50
First 400 kWh per month	$0.048000	$0.068402				$0.060788
Next 600 kWh per month	$0.048000	$0.077467				$0.075788
Over 1,000 kWh per month	$0.048000	$0.087467				$0.090788

MOHAVE ELECTRIC COOPERATIVE, INC.
SUMMARY OF RATES

	Existing Rate	Mohave Prop Rate	Staff Prop Rate	Mohave Rebuttal Rate		
				Phase 1	Phase 2	Phase 3
Power Cost, per kWh Sold	$0.089483	$0.089333	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Base Cost, per kWh Sold	$0.065798	$0.091183	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Factor, per kWh	$0.023685	($0.001850)	$0.000000	$0.000000	$0.000000	$0.000000
Irrigation						
Service Charge, per month	$60.00	$60.00	$61.76			$61.76
Demand Charge, per NCP kW	$7.00	$7.53	$7.42			$7.50
Energy Charge, per kWh	$0.058000	$0.084077	$0.082043			$0.082290
Irrigation Time of Use						
Service Charge, per month	$60.00	$65.00	$66.91			$66.91
On Peak Demand Charge, per on peak kW	$13.50	$8.90	$8.63			$8.90
Demand Charge, per NCP kW	$0.00	$1.63	$1.68			$1.60
Energy Charge, per kWh	$0.050000	$0.074077	$0.071792			$0.072219
Small Commercial - Energy						
Service Charge, per month	$12.00	$21.50	$17.00			$21.50
Energy Charge, per kWh	$0.081600	$0.105039	$0.107426			$0.103223
Small Commercial - Demand						
Service Charge, per month	$25.00	$35.00	$36.03			$36.03
Billing Demand Charge, per NCP kW > 3 kW	$8.25	$10.79	$10.74			$10.92
All kWh per month	$0.053740	$0.075507	$0.073351			$0.073191
Small Commercial - Time of Use						
Service Charge, per month	$30.00	$40.00	$41.01			$41.03
On Peak Demand Charge, per on peak kW	$12.50	$15.00	$14.45			$15.00
Demand Charge, per NCP kW		$4.48	$4.61			$4.61
All kWh per month	$0.050400	$0.062256	$0.060989			$0.059929

MOHAVE ELECTRIC COOPERATIVE, INC.

SUMMARY OF RATES

	Existing Rate	Mohave Prop Rate	Staff Prop Rate	Mohave Rebuttal Rate		
				Phase 1	Phase 2	Phase 3
Power Cost, per kWh Sold	$0.089483	$0.089333	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Base Cost, per kWh Sold	$0.065798	$0.091183	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Factor, per kWh	$0.023685	($0.001850)	$0.000000	$0.000000	$0.000000	$0.000000
Large Commercial & Industrial						
Customer Charge, per month	$70.00	$170.00	$175.00			$175.00
Demand Charge, per NCP kW	$9.75	$10.75	$10.89			$10.84
Energy Charge, per kWh	$0.045580	$0.072288	$0.070031			$0.070184
LC&I Time of Use (Existing Customers)						
Customer Charge, per month	$70.00	$175.00	$189.00	$180.00	$180.00	$180.00
On Peak Demand Charge, per on peak kW	$13.50	$23.00	$11.11	$11.11	$16.71	$23.00
Demand Charge, per NCP kW		$2.99	$3.08	$3.08	$3.08	$3.08
Energy Charge, per kWh	$0.041000	$0.053276	$0.051754	$0.050381	$0.050381	$0.050381
LC&I Time of Use (All New Customers)						
Customer Charge, per month	$70.00	$175.00	$189.00			$180.00
On Peak Demand Charge, per on peak kW	$13.50	$23.00	$11.11			$23.00
Demand Charge, per NCP kW		$2.99	$3.08			$3.08
Energy Charge, per kWh	$0.041000	$0.053276	$0.051754			$0.050381
Discount on Dem & Ener - Subtransmission Service	0.00%	-7.50%	-7.50%	-7.50%	-7.50%	-7.50%
Discount on Dem & Ener - Substation Service	0.00%	-5.00%	-5.00%	-5.00%	-5.00%	-5.00%
Discount on Dem & Ener - Dist Primary Service	0.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%

MOHAVE ELECTRIC COOPERATIVE, INC.

SUMMARY OF RATES

			Existing Rate	Mohave Prop Rate	Staff Prop Rate	Mohave Rebuttal Rate		
						Phase 1	Phase 2	Phase 3
Power Cost, per kWh Sold			$0.089483	$0.089333	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Base Cost, per kWh Sold			$0.065798	$0.091183	$0.087701	$0.089283	$0.089283	$0.089283
PPCA Factor, per kWh			$0.023685	($0.001850)	$0.000000	$0.000000	$0.000000	$0.000000
Lighting								
175 W MVL	100	kWh per month	$6.85	$7.32	$7.11			$7.13
100 W HPS	50	kWh per month	$7.88	$8.42	$8.46			$8.31
175 W MVL CO	100	kWh per month	$5.11	$6.49	$6.58			$6.62
100 W HPS CO	50	kWh per month	$5.11	$5.46	$5.41			$5.35
250 W HPS	129	kWh per month	$13.18	$14.09	$13.95			$13.86
			No PCA	*PCA*	*PCA*			*PCA*

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - *2010 USAGE*
RESIDENTIAL SERVICE

kWh Usage	Monthly * Cust	Existing Rate	Mohave Proposed	Staff Proposed	Mohave Rebuttal Phase 1	Mohave Rebuttal Phase 2	Mohave Rebuttal Phase 3	Change - $ Mohave	Change - $ Staff	Change - $ Phase 1	Change - $ Phase 2	Change - $ Phase 3	Change - % Mohave	Change - % Staff	Change - % Phase 1	Change - % Phase 2	Change - % Phase 3
Service Charge		$9.50	$16.50	$12.00	$12.00	$14.25	$16.50	$7.00	$2.50	$2.50	$4.75	$7.00	73.68%	26.32%	26.32%	50.00%	73.68%
Energy Charge, per kWh																	
First 400		$0.083190	$0.096373	$0.094823	$0.095136	$0.092556	$0.089976	$0.013183	$0.011633	$0.011946	$0.009366	$0.006786	15.85%	13.98%	14.36%	11.26%	8.16%
Next 600		$0.083190	$0.106373	$0.109823	$0.110136	$0.107556	$0.104976	$0.023183	$0.026633	$0.026946	$0.024366	$0.021786	27.87%	32.01%	32.39%	29.29%	26.19%
Over 1,000		$0.083190	$0.116373	$0.124823	$0.125136	$0.122556	$0.119976	$0.033183	$0.041633	$0.041946	$0.039366	$0.036786	39.89%	50.05%	50.42%	47.32%	44.22%
PPCA Factor		$0.023685	($0.001850)	$0.000000	$0.000000	$0.000000	$0.000000	($0.025535)	($0.023685)	($0.023685)	($0.023685)	($0.023685)	-107.81%	-100.00%	-100.00%	-100.00%	-100.00%
Total Energy Charge plus PPCA																	
First 400		$0.106875	$0.094523	$0.094823	$0.095136	$0.092556	$0.089976	($0.012352)	($0.012052)	($0.011739)	($0.014319)	($0.016899)	-11.56%	-11.28%	-10.98%	-13.40%	-15.81%
Next 600		$0.106875	$0.104523	$0.109823	$0.110136	$0.107556	$0.104976	($0.002352)	$0.002948	$0.003261	$0.000681	($0.001899)	-2.20%	2.76%	3.05%	0.64%	-1.78%
Over 1,000		$0.106875	$0.114523	$0.124823	$0.125136	$0.122556	$0.119976	$0.007648	$0.017948	$0.018261	$0.015681	$0.013101	7.16%	16.79%	17.09%	14.67%	12.26%
0	1,009	$9.50	$16.50	$12.00	$12.00	$14.25	$16.50	$7.00	$2.50	$2.50	$4.75	$7.00	73.68%	26.32%	26.32%	50.00%	73.68%
100	2,913	$20.19	$25.95	$21.48	$21.51	$23.51	$25.50	$5.76	$1.29	$1.33	$3.32	$5.31	28.56%	6.41%	6.67%	16.44%	26.30%
200	2,687	$30.88	$35.40	$30.96	$31.03	$32.76	$34.50	$4.53	$0.09	$0.15	$1.89	$3.62	14.67%	0.29%	0.49%	6.11%	11.73%
400	5,213	$52.25	$54.31	$49.93	$50.05	$51.27	$52.49	$2.06	($2.32)	($2.20)	($0.98)	$0.24	3.94%	-4.44%	-4.20%	-1.87%	0.46%
800	9,166	$95.00	$96.12	$93.86	$94.11	$94.29	$94.48	$1.12	($1.14)	($0.89)	($0.71)	($0.52)	1.18%	-1.20%	-0.94%	-0.74%	-0.55%
1,000	3,212	$116.38	$117.02	$115.82	$116.14	$115.81	$115.48	$0.65	($0.55)	($0.24)	($0.57)	($0.90)	0.56%	-0.47%	-0.21%	-0.49%	-0.77%
2,000	7,881	$223.25	$231.55	$240.65	$241.27	$238.36	$235.45	$8.30	$17.40	$18.02	$15.11	$12.20	3.72%	7.79%	8.07%	6.77%	5.47%
3,000	2,466	$330.13	$346.07	$365.47	$366.41	$360.92	$355.43	$15.94	$35.34	$36.28	$30.79	$25.30	4.83%	10.71%	10.99%	9.33%	7.66%
5,000	738	$543.88	$575.12	$615.12	$616.68	$606.03	$595.38	$31.24	$71.24	$72.80	$62.16	$51.51	5.74%	13.10%	13.39%	11.43%	9.47%
8,000	54	$864.50	$918.68	$989.58	$992.09	$973.70	$955.31	$54.18	$125.08	$127.59	$109.20	$90.81	6.27%	14.47%	14.76%	12.63%	10.50%
Over	4																
860 Average		$101.41	$102.39	$100.45	$100.72	$100.75	$100.78	$0.98	($0.96)	($0.70)	($0.66)	($0.63)	0.98%	-0.96%	-0.69%	-0.66%	-0.62%
637 Median		$77.58	$79.08	$75.96	$76.16	$76.76	$77.37	$1.50	($1.62)	($1.42)	($0.82)	($0.21)	1.94%	-2.09%	-1.83%	-1.06%	-0.27%

** Customers with usage from the previous block to this block*

MWS-Rebuttal Schedule 8

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISONS - 2010 USAGE
LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Mohave Proposed Rate			TOU Rate Change	
L.F.	Estimated On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$170.00	$175.00		$105.00	150%
On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
Demand Charge, per NCP kW					$9.75			$10.75	$2.99		$2.99	
Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276		$0.012276	30%
PPCA Factor					$0.023685	$0.023685		($0.001850)	($0.001850)		($0.025535)	-108%
20%	-	0%	300.00	43,800	$6,029	$2,903	$3,126	$6,480	$3,324	$3,156	$421	15%
40%	30.00	10%	300.00	87,600	$9,063	$6,141	$2,921	$9,565	$6,267	$3,298	$126	2%
60%	150.00	50%	300.00	131,400	$12,096	$10,595	$1,502	$12,651	$11,279	$1,371	$685	6%
80%	300.00	100%	300.00	175,200	$15,130	$15,453	$0	$15,736	$16,982	$0	$1,529	10%
20%	-	0%	1,000.00	146,000	$19,933	$9,514	$10,419	$21,204	$10,673	$10,531	$1,159	12%
40%	100.00	10%	1,000.00	292,000	$30,045	$20,308	$9,737	$31,488	$20,481	$11,007	$173	1%
60%	500.00	50%	1,000.00	438,000	$40,158	$35,152	$5,006	$41,772	$37,190	$4,582	$2,038	6%
80%	1,000.00	100%	1,000.00	584,000	$50,271	$51,346	$0	$52,056	$56,198	$0	$4,852	9%
20%	-	0%	5,000.00	730,000	$99,383	$47,290	$52,093	$105,340	$52,666	$52,674	$5,376	11%
40%	500.00	10%	5,000.00	1,460,000	$149,947	$101,260	$48,687	$156,759	$101,707	$55,053	$447	0%
60%	2,500.00	50%	5,000.00	2,190,000	$200,510	$175,480	$25,030	$208,179	$185,248	$22,931	$9,768	6%
80%	5,000.00	100%	5,000.00	2,920,000	$251,074	$256,450	$0	$259,599	$280,289	$0	$23,839	9%
20%	-	0%	10,000.00	1,460,000	$198,697	$94,510	$104,187	$210,509	$105,157	$105,353	$10,647	11%
40%	1,000.00	10%	10,000.00	2,920,000	$299,824	$202,450	$97,374	$313,349	$203,239	$110,110	$789	0%
60%	5,000.00	50%	10,000.00	4,380,000	$400,951	$350,890	$50,060	$416,188	$370,321	$45,868	$19,431	6%
80%	10,000.00	100%	10,000.00	5,840,000	$502,078	$512,830	$0	$519,028	$560,403	$0	$47,572	9%
Existing TOU Customers - 2010 Usage (Billed under Phase Three)												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,135	$20,874	$5,261	$3,071	17%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$26,871	$23,564	$3,307	$6,332	37%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,470	$23,007	$30,463	$10,008	77%
	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$106,476	$67,445	$39,031	$19,410	40%
Estimated On-Peak		100%										
Secondary												
59%	1,279.20	100%	1,279.20	554,400	$51,713	$53,971	$0	$54,842	$63,857	$0	$9,886	18%
49%	1,480.40	100%	1,480.40	531,560	$52,092	$55,209	$0	$55,396	$67,912	$0	$12,702	23%
80%	1,393.60	100%	1,393.60	809,120	$70,471	$71,992	$0	$74,014	$79,929	$0	$7,938	11%
80%	1,224.40	100%	1,224.40	713,440	$62,124	$63,448	$0	$65,286	$70,437	$0	$6,988	11%
77%	4,519.20	100%	4,519.20	2,542,320	$220,996	$226,299	$0	$229,697	$250,295	$0	$23,996	11%
86%	4,603.20	100%	4,603.20	2,873,760	$244,772	$248,872	$0	$253,946	$269,523	$0	$20,651	8%
53%	1,636.00	100%	1,636.00	634,960	$60,772	$63,998	$0	$64,352	$77,273	$0	$13,275	21%

1 **MOHAVE ELECTRIC COOPERATIVE, INC.**
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3 **COMPARISONS - 2010 USAGE**
4 **LC&I TIME OF USE (EXISTING CUSTOMERS)**
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Line	L.F.	Estimated On-Peak *		NCP kW	kWh	Existing LC&I Rate: Standard	Existing LC&I Rate: TOU	Existing LC&I Rate: TOU Savings	Mohave Proposed Rate: Standard	Mohave Proposed Rate: TOU	Mohave Proposed Rate: TOU Savings	TOU Rate Change: $	TOU Rate Change: %
11													
12	Customer Charge					$70.00	$70.00		$170.00	$175.00		$105.00	150%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.75	$2.99		$2.99	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276		$0.012276	30%
16	PPCA Factor					$0.023685	$0.023685		($0.001850)	($0.001850)		($0.025535)	-108%
17													
18													
57	41%	996.80	100%	996.80	299,680	$31,316	$33,682	$0	$33,864	$43,418	$0	$9,737	29%
58	38%	1,225.20	100%	1,225.20	335,400	$36,017	$39,076	$0	$38,836	$51,191	$0	$12,116	31%
59	38%	1,807.20	100%	1,807.20	500,720	$53,143	$57,626	$0	$56,737	$74,819	$0	$17,193	30%
60	39%	1,523.20	100%	1,523.20	431,840	$45,603	$49,337	$0	$48,832	$63,896	$0	$14,559	30%
61	33%	1,879.20	100%	1,879.20	449,880	$50,323	$55,310	$0	$53,930	$74,076	$0	$18,766	34%
62	71%	4,768.80	100%	4,768.80	2,488,800	$219,723	$226,207	$0	$228,611	$254,030	$0	$27,823	12%
63	70%	4,732.80	100%	4,732.80	2,433,520	$215,543	$222,145	$0	$224,330	$250,252	$0	$28,107	13%
64	63%	4,004.00	100%	4,004.00	1,854,560	$168,335	$174,856	$0	$175,714	$201,537	$0	$26,680	15%
65	70%	2,143.20	100%	2,143.20	1,099,280	$97,878	$100,880	$0	$102,510	$114,333	$0	$13,453	13%
66	69%	1,264.80	100%	1,264.80	640,240	$57,518	$59,329	$0	$60,734	$67,897	$0	$8,568	14%
67	46%	1,265.60	100%	1,265.60	422,400	$42,437	$45,249	$0	$45,398	$56,715	$0	$11,467	25%
68	50%	2,374.40	100%	2,374.40	868,240	$84,129	$89,057	$0	$88,722	$108,461	$0	$19,404	22%
69	50%	2,261.60	100%	2,261.60	825,760	$80,087	$84,786	$0	$84,517	$103,345	$0	$18,559	22%
70	35%	1,838.00	100%	1,838.00	468,560	$51,215	$55,962	$0	$54,803	$73,966	$0	$18,004	32%
71	92%	2,476.48	100%	2,476.48	1,654,720	$139,250	$140,958	$0	$144,367	$150,684	$0	$9,726	7%
72	76%	2,060.80	100%	2,060.80	1,144,800	$99,737	$102,222	$0	$103,641	$113,308	$0	$11,085	11%
73	74%	2,582.40	100%	2,582.40	1,398,720	$122,901	$126,179	$0	$128,324	$141,147	$0	$14,969	12%
74	76%	1,332.80	100%	1,332.80	735,040	$64,747	$66,379	$0	$68,142	$74,540	$0	$8,161	12%
75	53%	3,433.20	100%	3,433.20	1,336,080	$126,857	$133,613	$0	$133,058	$160,038	$0	$26,426	20%
76	41%	1,130.40	100%	1,130.40	335,200	$35,079	$37,783	$0	$37,803	$48,717	$0	$10,934	29%
77	74%	1,424.00	100%	1,424.00	769,480	$68,022	$69,838	$0	$71,549	$78,681	$0	$8,843	13%
78	29%	1,298.24	100%	1,298.24	271,200	$32,283	$35,909	$0	$35,099	$49,788	$0	$13,879	39%
79	57%	3,694.96	100%	3,694.96	1,533,760	$143,102	$149,933	$0	$149,796	$177,007	$0	$27,074	18%
80	119%	194.40	100%	194.40	168,800	$13,727	$13,683	$44	$14,320	$14,083	$237	$400	3%
81	57%	921.60	100%	921.60	384,800	$36,479	$38,172	$0	$39,052	$45,841	$0	$7,669	20%
82	53%	2,798.80	100%	2,798.80	1,073,520	$102,486	$108,064	$0	$107,744	$130,048	$0	$21,983	20%
83	31%	1,244.00	100%	1,244.00	280,280	$32,383	$35,764	$0	$35,155	$48,845	$0	$13,081	37%
84	45%	1,312.00	100%	1,312.00	428,920	$43,341	$46,297	$0	$46,356	$58,257	$0	$11,960	26%
85	41%	2,264.00	100%	2,264.00	681,440	$70,114	$75,483	$0	$74,377	$95,985	$0	$20,502	27%
86	62%	1,076.80	100%	1,076.80	485,920	$44,996	$46,809	$0	$47,843	$55,075	$0	$8,266	18%
87	64%	1,270.12	100%	1,270.12	592,360	$54,253	$56,303	$0	$57,418	$65,573	$0	$9,270	16%
88	60%	1,339.20	100%	1,339.20	583,360	$54,304	$56,654	$0	$57,527	$66,906	$0	$10,252	18%
89	48%	1,795.20	100%	1,795.20	631,520	$62,085	$65,925	$0	$65,821	$81,234	$0	$15,309	23%
90	26%	1,311.24	100%	1,311.24	249,840	$30,930	$34,703	$0	$33,734	$49,027	$0	$14,325	41%
91	55%	1,254.80	100%	1,254.80	500,640	$47,751	$50,164	$0	$50,793	$60,458	$0	$10,294	21%
92	55%	4,298.40	100%	4,298.40	1,710,240	$161,209	$169,495	$0	$168,714	$201,766	$0	$32,271	19%
93	58%	2,176.80	100%	2,176.80	914,160	$85,383	$89,359	$0	$89,832	$105,687	$0	$16,327	18%
94	68%	1,913.60	100%	1,913.60	952,720	$85,488	$88,300	$0	$89,719	$100,829	$0	$12,529	14%

1 MOHAVE ELECTRIC COOPERATIVE, INC.
2
3 COMPARISONS - 2010 USAGE
4 LC&I TIME OF USE (EXISTING CUSTOMERS)
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Line	L.F.	Estimated On-Peak *		NCP kW	kWh	Existing LC&I Rate Standard	Existing LC&I Rate TOU	Existing LC&I Rate TOU Savings	Mohave Proposed Rate Standard	Mohave Proposed Rate TOU	Mohave Proposed Rate TOU Savings	TOU Rate Change $	TOU Rate Change %
11													
12	Customer Charge					$70.00	$70.00		$170.00	$175.00		$105.00	150%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.75	$2.99		$2.99	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276		$0.012276	30%
16	PPCA Factor					$0.023685	$0.023685		($0.001850)	($0.001850)		($0.025535)	-108%
17													
18													
95	57%	3,940.00	100%	3,940.00	1,645,200	$153,210	$160,450	$0	$160,280	$189,107	$0	$28,657	18%
96	72%	1,972.00	100%	1,972.00	1,035,360	$91,781	$94,434	$0	$96,168	$106,597	$0	$12,162	13%
97	28%	1,599.20	100%	1,599.20	332,480	$39,461	$43,936	$0	$42,651	$60,761	$0	$16,826	38%
98	73%	1,786.40	100%	1,786.40	951,800	$84,184	$86,524	$0	$88,287	$97,476	$0	$10,952	13%
99	60%	1,177.60	100%	1,177.60	513,600	$47,896	$49,960	$0	$50,876	$59,118	$0	$9,158	18%
100	41%	1,767.60	100%	1,767.60	528,480	$54,679	$58,887	$0	$58,267	$75,218	$0	$16,330	28%
101	58%	2,883.60	100%	2,883.60	1,224,840	$113,794	$118,997	$0	$119,314	$140,033	$0	$21,036	18%
102	56%	5,476.00	100%	5,476.00	2,238,800	$209,301	$219,583	$0	$218,604	$259,554	$0	$39,971	18%
103	49%	1,643.20	100%	1,643.20	584,160	$57,323	$60,810	$0	$60,851	$74,848	$0	$14,038	23%
104	26%	2,480.40	100%	2,480.40	469,320	$57,531	$64,683	$0	$61,762	$90,701	$0	$26,017	40%
105	41%	1,113.60	100%	1,113.60	331,680	$34,671	$37,328	$0	$37,374	$48,099	$0	$10,771	29%
106	14%	686.40	100%	686.40	72,360	$11,914	$14,157	$0	$12,986	$22,086	$0	$7,929	56%
107	19%	1,121.08	100%	1,121.08	158,040	$22,367	$25,847	$0	$24,374	$38,489	$0	$12,642	49%
108	54%	1,704.00	100%	1,704.00	669,200	$63,806	$67,131	$0	$67,495	$80,801	$0	$13,670	20%
109	34%	1,952.00	100%	1,952.00	480,080	$53,125	$58,246	$0	$56,840	$77,521	$0	$19,275	33%
110	55%	1,204.00	100%	1,204.00	480,160	$45,837	$48,153	$0	$48,805	$58,085	$0	$9,932	21%
111	22%	271.04	100%	271.04	43,538	$5,868	$6,685	$0	$6,490	$9,808	$0	$3,123	47%
112	0%	90.00	100%	90.00	200	$961	$1,298	$0	$1,152	$2,524	$0	$1,226	94%
113	74%	7,430.40	100%	7,430.40	4,032,000	$352,563	$361,960	$0	$365,923	$402,566	$0	$40,605	11%
114	73%	9,698.40	100%	9,698.40	5,163,840	$453,073	$465,791	$0	$470,028	$519,717	$0	$53,926	12%
115	51%	1,256.80	100%	1,256.80	463,680	$45,211	$47,800	$0	$48,211	$58,609	$0	$10,809	23%
116	50%	1,598.40	100%	1,598.40	578,880	$56,521	$59,863	$0	$59,998	$73,412	$0	$13,549	23%
117	78%	1,464.80	100%	1,464.80	837,840	$73,155	$74,810	$0	$76,802	$83,257	$0	$8,446	11%
118	53%	353.88	100%	353.88	136,920	$13,284	$13,984	$0	$14,299	$17,114	$0	$3,130	22%
119	52%	7,406.40	100%	7,406.40	2,785,920	$266,019	$281,034	$0	$277,893	$337,861	$0	$56,827	20%
120	30%	716.80	100%	716.80	158,960	$18,839	$20,799	$0	$20,942	$28,904	$0	$8,105	39%
121	3%	3,231.20	100%	3,231.20	75,120	$37,547	$49,320	$0	$42,067	$89,942	$0	$40,622	82%
122	12%	774.00	100%	774.00	69,840	$12,804	$15,387	$0	$14,260	$24,758	$0	$9,371	61%
123	55%	118.00	100%	118.00	47,600	$4,518	$4,742	$0	$4,791	$5,690	$0	$948	20%
124	49%	1,656.00	100%	1,656.00	587,040	$57,647	$61,169	$0	$61,192	$75,329	$0	$14,160	23%
125	40%	2,059.20	100%	2,059.20	607,440	$62,992	$67,931	$0	$66,963	$86,857	$0	$18,925	28%
126	8%	1,350.84	100%	1,350.84	79,400	$19,510	$24,212	$0	$22,154	$41,292	$0	$17,079	71%
127	43%	1,880.00	100%	1,880.00	586,600	$59,801	$64,164	$0	$63,569	$81,128	$0	$16,963	26%
128	60%	5,217.44	100%	5,217.44	2,291,360	$210,421	$219,492	$0	$219,526	$255,537	$0	$36,045	16%
129	60%	2,221.00	100%	2,221.00	980,680	$90,422	$94,259	$0	$94,993	$110,256	$0	$15,997	17%
130	54%	2,441.60	100%	2,441.60	967,840	$91,683	$96,406	$0	$96,460	$115,329	$0	$18,923	20%
131	44%	3,156.80	100%	3,156.80	1,015,120	$101,931	$109,120	$0	$107,479	$136,349	$0	$27,229	25%
132	49%	1,095.76	100%	1,095.76	390,240	$38,554	$40,875	$0	$41,307	$50,647	$0	$9,772	24%

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Row	L.F.	Estimated On-Peak *		NCP kW	kWh	Existing LC&I Rate Standard	Existing LC&I Rate TOU	Existing LC&I Rate TOU Savings	Mohave Proposed Rate Standard	Mohave Proposed Rate TOU	Mohave Proposed Rate TOU Savings	TOU Rate Change $	TOU Rate Change %
11													
12	Customer Charge					$70.00	$70.00		$170.00	$175.00		$105.00	150%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.75	$2.99		$2.99	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276		$0.012276	30%
16	PPCA Factor					$0.023685	$0.023685		($0.001850)	($0.001850)		($0.025535)	-108%
17													
18													
133	46%	1,324.40	100%	1,324.40	449,240	$44,870	$47,778	$0	$47,921	$59,624	$0	$11,845	25%
134	63%	312.28	100%	312.28	143,160	$13,801	$14,316	$0	$15,481	$17,578	$0	$3,262	23%
135	28%	548.60	100%	548.60	113,200	$13,680	$15,218	$0	$15,061	$21,305	$0	$6,086	40%
136	45%	996.76	100%	996.76	330,760	$33,469	$35,691	$0	$36,053	$45,015	$0	$9,324	26%
137	31%	3,238.64	100%	3,238.64	726,160	$82,714	$91,533	$0	$88,005	$123,616	$0	$32,082	35%
138	64%	2,014.00	100%	2,014.00	937,600	$85,349	$88,608	$0	$89,563	$102,486	$0	$13,878	16%
139	12%	113.60	100%	113.60	9,600	$1,843	$2,225	$0	$2,067	$3,621	$0	$1,397	63%
140	Correction	-	100%		(610,240)	($42,198)	($39,403)	$0	($42,814)	($31,207)	$0	$8,196	-21%
141	Total	189,369.16		189,369.16	76,311,058	$7,200,845	$7,561,474	$44	$7,578,027	$9,018,102	$237	$1,456,627	19%
142													
143	**Secondary Governmental**												
144	46%	1,217.60	100%	1,217.60	406,880	$40,894	$43,597	$0	$43,789	$54,670	$0	$11,073	25%
145	40%	1,855.20	100%	1,855.20	535,560	$56,024	$60,528	$0	$59,707	$77,858	$0	$17,330	29%
146	37%	5,646.40	100%	5,646.40	1,543,520	$162,804	$176,909	$0	$171,461	$228,227	$0	$51,318	29%
147	35%	5,715.20	100%	5,715.20	1,456,960	$157,480	$172,239	$0	$166,104	$225,564	$0	$53,325	31%
148	20%	1,587.20	100%	1,587.20	232,080	$32,390	$37,279	$0	$35,450	$55,286	$0	$18,007	48%
149	5%	1,248.00	100%	1,248.00	43,280	$16,006	$20,488	$0	$18,505	$36,761	$0	$16,274	79%
150	22%	1,771.20	100%	1,771.20	285,920	$37,913	$43,246	$0	$41,220	$62,837	$0	$19,591	45%
151	58%	1,186.40	100%	1,186.40	503,600	$47,289	$49,432	$0	$50,266	$58,833	$0	$9,401	19%
152	30%	1,023.60	100%	1,023.60	225,000	$26,405	$29,213	$0	$28,892	$40,274	$0	$11,061	38%
153	28%	2,095.92	100%	2,095.92	433,800	$51,322	$57,195	$0	$55,127	$78,882	$0	$21,686	38%
154	28%	1,768.00	100%	1,768.00	356,800	$42,792	$47,788	$0	$46,178	$66,399	$0	$18,612	39%
155	39%	3,160.00	100%	3,160.00	911,000	$94,750	$102,428	$0	$100,179	$131,077	$0	$28,649	28%
156	32%	3,054.00	100%	3,054.00	718,200	$80,363	$88,526	$0	$85,459	$118,408	$0	$29,882	34%
157	31%	2,018.60	100%	2,018.60	457,800	$52,231	$57,704	$0	$55,986	$78,106	$0	$20,402	35%
158	29%	2,812.00	100%	2,812.00	596,800	$69,594	$77,406	$0	$74,306	$105,875	$0	$28,469	37%
159	33%	2,516.00	100%	2,516.00	614,600	$67,941	$74,561	$0	$72,378	$99,097	$0	$24,536	33%
160	35%	1,354.44	100%	1,354.44	341,760	$37,718	$41,232	$0	$40,673	$54,877	$0	$13,646	33%
161	51%	1,436.40	100%	1,436.40	538,200	$52,123	$55,045	$0	$55,391	$67,110	$0	$12,065	22%
162	57%	1,936.80	100%	1,936.80	804,480	$75,446	$79,025	$0	$79,527	$93,809	$0	$14,784	19%
163	65%	3,676.80	100%	3,676.80	1,742,400	$157,376	$163,184	$0	$164,297	$187,265	$0	$24,081	15%
164	47%	2,390.40	100%	2,390.40	827,040	$81,431	$86,607	$0	$85,992	$106,758	$0	$20,150	23%
165	7%	3,295.20	100%	3,295.20	160,560	$44,089	$55,711	$0	$48,773	$95,999	$0	$40,288	72%
166	45%	1,655.20	100%	1,655.20	537,760	$54,226	$57,970	$0	$57,712	$72,773	$0	$14,803	26%
167	96%	2,008.80	100%	2,008.80	1,413,960	$118,364	$119,421	$0	$123,231	$127,023	$0	$7,602	6%
168	11%	1,444.40	100%	1,444.40	116,040	$22,960	$27,845	$0	$25,741	$45,607	$0	$17,762	64%
169	4%	926.40	100%	926.40	24,480	$11,568	$14,930	$0	$13,723	$27,436	$0	$12,506	84%
170	54%	988.40	100%	988.40	386,240	$37,230	$39,167	$0	$39,871	$47,651	$0	$8,484	22%

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8						Existing LC&I Rate			Mohave Proposed Rate			TOU Rate Change	
9 / 10	L.F.	Estimated On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$170.00	$175.00		$105.00	150%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.75	$2.99		$2.99	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276		$0.012276	30%
16	PPCA Factor					$0.023685	$0.023685		($0.001850)	($0.001850)		($0.025535)	-108%
17													
18													
171	48%	1,586.80	100%	1,586.80	550,360	$54,432	$57,862	$0	$57,864	$71,644	$0	$13,782	24%
172	31%	1,394.80	100%	1,394.80	315,600	$36,299	$40,084	$0	$39,264	$54,581	$0	$14,497	36%
173	19%	1,011.60	100%	1,011.60	138,600	$19,813	$22,972	$0	$21,487	$34,294	$0	$11,322	49%
174	28%	561.60	100%	561.60	114,480	$13,685	$15,267	$0	$14,781	$21,183	$0	$5,916	39%
175	Correction	-	100%		(153,600)	($10,289)	($9,586)	$0	($9,969)	($7,024)	$0	$2,562	-27%
176	Total	64,343.36		64,343.36	17,180,160	$1,842,672	$2,005,274	$0	$1,963,367	$2,619,141	$0	$613,867	31%
177													
178	Primary												
179	51%	3,924.00	100%	3,924.00	1,459,200	$140,170	$148,202	$0	$145,509	$177,307	$0	$29,105	20%
180	75%	11,952.00	100%	11,952.00	6,542,280	$570,523	$585,379	$0	$585,315	$642,563	$0	$57,184	10%
181	52%	1,296.00	100%	1,296.00	495,840	$47,820	$50,409	$0	$50,380	$60,660	$0	$10,251	20%
182	Total	17,172.00		17,172.00	8,497,320	$758,514	$783,991	$0	$781,203	$880,530	$0	$96,539	12%
183													
184	Transmission (Billed as TOU in Test Year - Assumed Non-TOU under new rates)												
185	78%	49,732.47	94%	53,106.00	30,204,000	$2,610,704	$2,625,974	$0	$2,493,715	$2,639,463	$0	$13,489	1%
186													
187	Substation												
188	81%	60,072.00	100%	60,072.00	35,668,800	$3,057,141	$3,119,048	$0	$2,998,941	$3,224,492	$0	$105,444	3%
189	58%	7,428.00	100%	7,428.00	3,133,200	$290,284	$303,789	$0	$287,168	$338,178	$0	$34,389	11%
190	Total	67,500.00		67,500.00	38,802,000	$3,347,426	$3,422,837	$0	$3,286,109	$3,562,670	$0	$139,832	4%
191													
192	Total Lost Revenue										$237		

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LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Staff's Proposed Rate			TOU Rate Change	
L.F.	Estimated On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$175.00	$189.00		$119.00	170%
On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
Demand Charge, per NCP kW					$9.75			$10.89	$3.08		$3.08	
Energy Charge, per kWh					$0.045580	$0.041000		$0.070031	$0.051754		$0.01	26%
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.02)	-100%
20%	-	0%	300.00	43,800	$6,029	$2,903	$3,126	$6,509	$3,380	$3,130	$477	16%
40%	30.00	10%	300.00	87,600	$9,063	$6,141	$2,921	$9,577	$5,980	$3,597	($161)	-3%
60%	150.00	50%	300.00	131,400	$12,096	$10,595	$1,502	$12,644	$9,580	$3,064	($1,015)	-10%
80%	300.00	100%	300.00	175,200	$15,130	$15,453	$0	$15,711	$13,513	$2,198	($1,940)	-13%
20%	-	0%	1,000.00	146,000	$19,933	$9,514	$10,419	$21,290	$10,825	$10,464	$1,311	14%
40%	100.00	10%	1,000.00	292,000	$30,045	$20,308	$9,737	$31,514	$19,492	$12,022	($816)	-4%
60%	500.00	50%	1,000.00	438,000	$40,158	$35,152	$5,006	$41,739	$31,492	$10,246	($3,660)	-10%
80%	1,000.00	100%	1,000.00	584,000	$50,271	$51,346	$0	$51,963	$44,603	$7,360	($6,743)	-13%
20%	-	0%	5,000.00	730,000	$99,383	$47,290	$52,093	$105,748	$53,369	$52,378	$6,079	13%
40%	500.00	10%	5,000.00	1,460,000	$149,947	$101,260	$48,687	$156,870	$96,705	$60,165	($4,555)	-4%
60%	2,500.00	50%	5,000.00	2,190,000	$200,510	$175,480	$25,030	$207,993	$156,705	$51,288	($18,775)	-11%
80%	5,000.00	100%	5,000.00	2,920,000	$251,074	$256,450	$0	$259,116	$222,261	$36,855	($34,190)	-13%
20%	-	0%	10,000.00	1,460,000	$198,697	$94,510	$104,187	$211,320	$106,550	$104,770	$12,040	13%
40%	1,000.00	10%	10,000.00	2,920,000	$299,824	$202,450	$97,374	$313,566	$193,221	$120,345	($9,230)	-5%
60%	5,000.00	50%	10,000.00	4,380,000	$400,951	$350,890	$50,060	$415,811	$313,222	$102,589	($37,669)	-11%
80%	10,000.00	100%	10,000.00	5,840,000	$502,078	$512,830	$0	$518,056	$444,332	$73,724	($68,498)	-13%
Existing TOU Customers - 2010 Usage (Billed under Phase Three)												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,216	$18,240	$7,977	$436	2%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$27,028	$19,177	$7,851	$1,945	11%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,956	$22,949	$31,008	$9,949	77%
	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$107,201	$60,365	$46,836	$12,330	26%
Estimated On-Peak		100%										
Secondary												
59%	1,279.20	100%	1,279.20	554,400	$51,713	$53,971	$0	$54,856	$49,112	$5,743	($4,858)	-9%
49%	1,480.40	100%	1,480.40	531,560	$52,092	$55,209	$0	$55,447	$50,785	$4,662	($4,424)	-8%
80%	1,393.60	100%	1,393.60	809,120	$70,471	$71,992	$0	$73,940	$63,918	$10,021	($8,073)	-11%
80%	1,224.40	100%	1,224.40	713,440	$62,124	$63,448	$0	$65,222	$56,377	$8,845	($7,072)	-11%
77%	4,519.20	100%	4,519.20	2,542,320	$220,996	$226,299	$0	$229,355	$197,971	$31,385	($28,328)	-13%
86%	4,603.20	100%	4,603.20	2,873,760	$244,772	$248,872	$0	$253,481	$216,316	$37,165	($32,556)	-13%
53%	1,636.00	100%	1,636.00	634,960	$60,772	$63,998	$0	$64,383	$58,345	$6,038	($5,654)	-9%

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Row						Existing LC&I Rate			Staff's Proposed Rate			TOU Rate Change	
8													
9		Estimated		NCP				TOU			TOU		
10	L.F.	On-Peak *		kW	kWh	Standard	TOU	Savings	Standard	TOU	Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$175.00	$189.00		$119.00	170%
13	On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
14	Demand Charge, per NCP kW					$9.75			$10.89	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070031	$0.051754		$0.01	26%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.02)	-100%
17													
18													
57	41%	996.80	100%	996.80	299,680	$31,316	$33,682	$0	$33,942	$31,922	$2,020	($1,759)	-5%
58	38%	1,225.20	100%	1,225.20	335,400	$36,017	$39,076	$0	$38,931	$37,012	$1,919	($2,064)	-5%
59	38%	1,807.20	100%	1,807.20	500,720	$53,143	$57,626	$0	$56,846	$53,826	$3,020	($3,800)	-7%
60	39%	1,523.20	100%	1,523.20	431,840	$45,603	$49,337	$0	$48,930	$46,232	$2,698	($3,105)	-6%
61	33%	1,879.20	100%	1,879.20	449,880	$50,323	$55,310	$0	$54,070	$52,217	$1,853	($3,093)	-6%
62	71%	4,768.80	100%	4,768.80	2,488,800	$219,723	$226,207	$0	$228,325	$198,743	$29,583	($27,464)	-12%
63	70%	4,732.80	100%	4,732.80	2,433,520	$215,543	$222,145	$0	$224,062	$195,371	$28,691	($26,774)	-12%
64	63%	4,004.00	100%	4,004.00	1,854,560	$168,335	$174,856	$0	$175,580	$155,066	$20,515	($19,791)	-11%
65	70%	2,143.20	100%	2,143.20	1,099,280	$97,878	$100,880	$0	$102,423	$89,572	$12,851	($11,308)	-11%
66	69%	1,264.80	100%	1,264.80	640,240	$57,518	$59,329	$0	$60,710	$53,350	$7,360	($5,978)	-10%
67	46%	1,265.60	100%	1,265.60	422,400	$42,437	$45,249	$0	$45,463	$42,088	$3,376	($3,161)	-7%
68	50%	2,374.40	100%	2,374.40	868,240	$84,129	$89,057	$0	$88,761	$80,896	$7,865	($8,161)	-9%
69	50%	2,261.60	100%	2,261.60	825,760	$80,087	$84,786	$0	$84,558	$77,096	$7,461	($7,689)	-9%
70	35%	1,838.00	100%	1,838.00	468,560	$51,215	$55,962	$0	$54,930	$52,599	$2,330	($3,363)	-6%
71	92%	2,476.48	100%	2,476.48	1,654,720	$139,250	$140,958	$0	$144,076	$122,103	$21,973	($18,855)	-13%
72	76%	2,060.80	100%	2,060.80	1,144,800	$99,737	$102,222	$0	$103,489	$89,436	$14,053	($12,786)	-13%
73	74%	2,582.40	100%	2,582.40	1,398,720	$122,901	$126,179	$0	$128,176	$111,302	$16,874	($14,877)	-12%
74	76%	1,332.80	100%	1,332.80	735,040	$64,747	$66,379	$0	$68,090	$59,222	$8,868	($7,157)	-11%
75	53%	3,433.20	100%	3,433.20	1,336,080	$126,857	$133,613	$0	$133,055	$120,133	$12,922	($13,480)	-10%
76	41%	1,130.40	100%	1,130.40	335,200	$35,079	$37,783	$0	$37,884	$35,656	$2,228	($2,126)	-6%
77	74%	1,424.00	100%	1,424.00	769,480	$68,022	$69,838	$0	$71,495	$62,298	$9,197	($7,540)	-11%
78	29%	1,298.24	100%	1,298.24	271,200	$32,283	$35,909	$0	$35,230	$34,726	$505	($1,183)	-3%
79	57%	3,694.96	100%	3,694.96	1,533,760	$143,102	$149,933	$0	$149,749	$134,078	$15,671	($15,856)	-11%
80	119%	194.40	100%	194.40	168,800	$13,727	$13,683	$44	$14,288	$11,873	$2,416	($1,811)	-13%
81	57%	921.60	100%	921.60	384,800	$36,479	$38,172	$0	$39,084	$35,260	$3,824	($2,912)	-8%
82	53%	2,798.80	100%	2,798.80	1,073,520	$102,486	$108,064	$0	$107,759	$97,542	$10,217	($10,523)	-10%
83	31%	1,244.00	100%	1,244.00	280,280	$32,383	$35,764	$0	$35,275	$34,426	$849	($1,338)	-4%
84	45%	1,312.00	100%	1,312.00	428,920	$43,341	$46,297	$0	$46,425	$43,084	$3,342	($3,213)	-7%
85	41%	2,264.00	100%	2,264.00	681,440	$70,114	$75,483	$0	$74,477	$69,661	$4,815	($5,822)	-8%
86	62%	1,076.80	100%	1,076.80	485,920	$44,996	$46,809	$0	$47,856	$42,696	$5,160	($4,112)	-9%
87	64%	1,270.12	100%	1,270.12	592,360	$54,253	$56,303	$0	$57,415	$50,948	$6,467	($5,355)	-10%
88	60%	1,339.20	100%	1,339.20	583,360	$54,304	$56,654	$0	$57,537	$51,462	$6,075	($5,191)	-9%
89	48%	1,795.20	100%	1,795.20	631,520	$62,085	$65,925	$0	$65,876	$60,426	$5,450	($5,499)	-8%
90	26%	1,311.24	100%	1,311.24	249,840	$30,930	$34,703	$0	$33,876	$33,805	$71	($898)	-3%
91	55%	1,254.80	100%	1,254.80	500,640	$47,751	$50,164	$0	$50,825	$45,984	$4,841	($4,180)	-8%
92	55%	4,298.40	100%	4,298.40	1,710,240	$161,209	$169,495	$0	$168,679	$151,774	$16,905	($17,721)	-10%
93	58%	2,176.80	100%	2,176.80	914,160	$85,383	$89,359	$0	$89,825	$80,468	$9,357	($8,891)	-10%
94	68%	1,913.60	100%	1,913.60	952,720	$85,488	$88,300	$0	$89,659	$78,729	$10,930	($9,571)	-11%

1 MOHAVE ELECTRIC COOPERATIVE, INC.

3 COMPARISONS - 2010 USAGE

4 LC&I TIME OF USE (EXISTING CUSTOMERS)

						Existing LC&I Rate			Staff's Proposed Rate			TOU Rate Change	
8–10	L.F.	Estimated On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
12	Customer Charge					$70.00	$70.00		$175.00	$189.00		$119.00	170%
13	On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
14	Demand Charge, per NCP kW					$9.75			$10.89	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070031	$0.051754		$0.01	26%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.02)	-100%
95	57%	3,940.00	100%	3,940.00	1,645,200	$153,210	$160,450	$0	$160,222	$143,322	$16,899	($17,127)	-11%
96	72%	1,972.00	100%	1,972.00	1,035,360	$91,781	$94,434	$0	$96,082	$83,835	$12,248	($10,600)	-11%
97	28%	1,599.20	100%	1,599.20	332,480	$39,461	$43,936	$0	$42,799	$42,168	$631	($1,768)	-4%
98	73%	1,786.40	100%	1,786.40	951,800	$84,184	$86,524	$0	$88,209	$76,876	$11,333	($9,647)	-11%
99	60%	1,177.60	100%	1,177.60	513,600	$47,896	$49,960	$0	$50,892	$45,559	$5,333	($4,401)	-9%
100	41%	1,767.60	100%	1,767.60	528,480	$54,679	$58,887	$0	$58,359	$54,701	$3,658	($4,186)	-7%
101	58%	2,883.60	100%	2,883.60	1,224,840	$113,794	$118,997	$0	$119,279	$106,577	$12,703	($12,421)	-10%
102	56%	5,476.00	100%	5,476.00	2,238,800	$209,301	$219,583	$0	$218,519	$195,839	$22,680	($23,743)	-11%
103	49%	1,643.20	100%	1,643.20	584,160	$57,323	$60,810	$0	$60,904	$55,818	$5,086	($4,992)	-8%
104	26%	2,480.40	100%	2,480.40	469,320	$57,531	$64,683	$0	$61,979	$61,754	$224	($2,929)	-5%
105	41%	1,113.60	100%	1,113.60	331,680	$34,671	$37,328	$0	$37,455	$35,236	$2,219	($2,093)	-6%
106	14%	686.40	100%	686.40	72,360	$11,914	$14,157	$0	$13,067	$14,052	$0	($105)	-1%
107	19%	1,121.08	100%	1,121.08	158,040	$22,367	$25,847	$0	$24,501	$25,410	$0	($437)	-2%
108	54%	1,704.00	100%	1,704.00	669,200	$63,606	$67,131	$0	$67,521	$61,082	$6,440	($6,050)	-9%
109	34%	1,952.00	100%	1,952.00	480,080	$53,125	$58,246	$0	$56,978	$54,813	$2,165	($3,433)	-6%
110	55%	1,204.00	100%	1,204.00	480,160	$45,837	$48,153	$0	$48,838	$44,203	$4,635	($3,950)	-8%
111	22%	271.04	100%	271.04	43,538	$5,868	$6,685	$0	$6,526	$6,666	$0	($19)	0%
112	0%	90.00	100%	90.00	200	$961	$1,298	$0	$1,169	$1,476	$0	$178	14%
113	74%	7,430.40	100%	7,430.40	4,032,000	$352,563	$361,960	$0	$365,382	$316,378	$49,005	($45,583)	-13%
114	73%	9,698.40	100%	9,698.40	5,163,840	$453,073	$465,791	$0	$469,344	$407,138	$62,207	($58,654)	-13%
115	51%	1,256.80	100%	1,256.80	463,680	$45,211	$47,800	$0	$48,259	$44,099	$4,159	($3,701)	-8%
116	50%	1,598.40	100%	1,598.40	578,880	$56,521	$59,863	$0	$60,046	$54,909	$5,137	($4,955)	-8%
117	78%	1,464.80	100%	1,464.80	837,840	$73,155	$74,810	$0	$76,726	$66,415	$10,311	($8,395)	-11%
118	53%	353.88	100%	353.88	136,920	$13,284	$13,984	$0	$14,317	$13,053	$1,265	($931)	-7%
119	52%	7,406.40	100%	7,406.40	2,785,920	$266,019	$281,034	$0	$277,856	$251,547	$26,309	($29,486)	-10%
120	30%	716.80	100%	716.80	158,960	$18,839	$20,799	$0	$21,038	$20,666	$372	($133)	-1%
121	3%	3,231.20	100%	3,231.20	75,120	$37,547	$49,320	$0	$42,548	$52,006	$0	$2,686	5%
122	12%	774.00	100%	774.00	69,840	$12,804	$15,387	$0	$14,370	$15,732	$0	$345	2%
123	55%	118.00	100%	118.00	47,600	$4,518	$4,742	$0	$4,793	$4,327	$467	($415)	-9%
124	49%	1,656.00	100%	1,656.00	587,040	$57,647	$61,169	$0	$61,245	$56,148	$5,097	($5,020)	-8%
125	40%	2,059.20	100%	2,059.20	607,440	$62,992	$67,931	$0	$67,064	$62,925	$4,139	($5,006)	-7%
126	8%	1,350.84	100%	1,350.84	79,400	$19,510	$24,212	$0	$22,371	$25,546	$0	$1,333	6%
127	43%	1,880.00	100%	1,880.00	586,600	$59,801	$64,164	$0	$63,653	$59,304	$4,349	($4,860)	-8%
128	60%	5,217.44	100%	5,217.44	2,291,360	$210,421	$219,492	$0	$219,384	$194,891	$24,494	($24,602)	-11%
129	60%	2,221.00	100%	2,221.00	980,680	$90,422	$94,259	$0	$94,965	$84,538	$10,427	($9,721)	-10%
130	54%	2,441.60	100%	2,441.60	967,840	$91,683	$96,406	$0	$96,468	$87,004	$9,464	($9,402)	-10%
131	44%	3,156.80	100%	3,156.80	1,015,120	$101,931	$109,120	$0	$107,567	$99,600	$7,968	($9,520)	-9%
132	49%	1,095.76	100%	1,095.76	390,240	$38,554	$40,875	$0	$41,362	$38,013	$3,348	($2,862)	-7%

1 MOHAVE ELECTRIC COOPERATIVE, INC.
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3 COMPARISONS - 2010 USAGE
4 LC&I TIME OF USE (EXISTING CUSTOMERS)
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8						Existing LC&I Rate			Staff's Proposed Rate			TOU Rate Change	
9		Estimated		NCP				TOU			TOU		
10	L.F.	On-Peak *		kW	kWh	Standard	TOU	Savings	Standard	TOU	Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$175.00	$189.00		$119.00	170%
13	On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
14	Demand Charge, per NCP kW					$9.75			$10.89	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070031	$0.051754		$0.01	26%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.02)	-100%
17													
18													
133	46%	1,324.40	100%	1,324.40	449,240	$44,870	$47,778	$0	$47,983	$44,311	$3,672	($3,467)	-7%
134	63%	312.28	100%	312.28	143,160	$13,801	$14,316	$0	$15,526	$14,108	$1,418	($208)	-1%
135	28%	548.60	100%	548.60	113,200	$13,680	$15,218	$0	$15,127	$14,966	$161	($252)	-2%
136	45%	996.76	100%	996.76	330,760	$33,469	$35,691	$0	$36,118	$33,530	$2,588	($2,161)	-6%
137	31%	3,238.64	100%	3,238.64	726,160	$82,714	$91,533	$0	$88,223	$85,806	$2,417	($5,727)	-6%
138	64%	2,014.00	100%	2,014.00	937,600	$85,349	$88,608	$0	$89,519	$79,182	$10,336	($9,425)	-11%
139	12%	113.60	100%	113.60	9,600	$1,843	$2,225	$0	$2,084	$2,298	$0	$73	3%
140	Correction	-	100%		(610,240)	($42,198)	($39,403)	$0	($42,561)	($31,393)	$0	$8,010	-20%
141	Total	189,369.16		189,369.16	76,311,058	$7,200,845	$7,561,474	$44	$7,578,395	$6,822,338	$783,774	($739,137)	-10%
142													
143	**Secondary Governmental**												
144	46%	1,217.60	100%	1,217.60	406,880	$40,894	$43,597	$0	$43,854	$40,603	$3,250	($2,993)	-7%
145	40%	1,855.20	100%	1,855.20	535,560	$56,024	$60,528	$0	$59,809	$56,311	$3,498	($4,217)	-7%
146	37%	5,646.40	100%	5,646.40	1,543,520	$162,804	$176,909	$0	$171,684	$162,274	$9,410	($14,635)	-8%
147	35%	5,715.20	100%	5,715.20	1,456,960	$157,480	$172,239	$0	$166,371	$158,770	$7,601	($13,468)	-8%
148	20%	1,587.20	100%	1,587.20	232,080	$32,390	$37,279	$0	$35,637	$36,801	$0	($478)	-1%
149	5%	1,248.00	100%	1,248.00	43,280	$16,006	$20,488	$0	$18,722	$22,217	$0	$1,729	8%
150	22%	1,771.20	100%	1,771.20	285,920	$37,913	$43,246	$0	$41,412	$42,199	$0	($1,047)	-2%
151	58%	1,186.40	100%	1,186.40	503,600	$47,289	$49,432	$0	$50,288	$45,166	$5,121	($4,265)	-9%
152	30%	1,023.60	100%	1,023.60	225,000	$26,405	$29,213	$0	$29,004	$28,438	$566	($775)	-3%
153	28%	2,095.92	100%	2,095.92	433,800	$51,322	$57,195	$0	$55,304	$54,460	$844	($2,735)	-5%
154	28%	1,768.00	100%	1,768.00	356,800	$42,792	$47,788	$0	$46,341	$45,822	$519	($1,966)	-4%
155	39%	3,160.00	100%	3,160.00	911,000	$94,750	$102,428	$0	$100,311	$94,256	$6,054	($8,172)	-8%
156	32%	3,054.00	100%	3,054.00	718,200	$80,363	$88,526	$0	$85,654	$82,774	$2,880	($5,752)	-6%
157	31%	2,018.60	100%	2,018.60	457,800	$52,231	$57,704	$0	$56,143	$54,605	$1,538	($3,099)	-5%
158	29%	2,812.00	100%	2,812.00	596,800	$69,594	$77,406	$0	$74,517	$73,057	$1,460	($4,349)	-6%
159	33%	2,516.00	100%	2,516.00	614,600	$67,941	$74,561	$0	$72,540	$69,778	$2,762	($4,783)	-6%
160	35%	1,354.44	100%	1,354.44	341,760	$37,718	$41,232	$0	$40,784	$39,175	$1,609	($2,057)	-5%
161	51%	1,436.40	100%	1,436.40	538,200	$52,123	$55,045	$0	$55,433	$50,505	$4,929	($4,540)	-8%
162	57%	1,936.80	100%	1,936.80	804,480	$75,446	$79,025	$0	$79,530	$71,386	$8,144	($7,638)	-10%
163	65%	3,676.80	100%	3,676.80	1,742,400	$157,376	$163,184	$0	$164,162	$144,618	$19,544	($18,566)	-11%
164	47%	2,390.40	100%	2,390.40	827,040	$81,431	$86,607	$0	$86,050	$78,990	$7,059	($7,617)	-9%
165	7%	3,295.20	100%	3,295.20	160,560	$44,089	$55,711	$0	$49,229	$57,337	$0	$1,625	3%
166	45%	1,655.20	100%	1,655.20	537,760	$54,226	$57,970	$0	$57,785	$53,587	$4,198	($4,384)	-8%
167	96%	2,008.80	100%	2,008.80	1,413,960	$118,364	$119,421	$0	$122,997	$103,951	$19,046	($15,470)	-13%
168	11%	1,444.40	100%	1,444.40	116,040	$22,960	$27,845	$0	$25,956	$28,770	$0	$924	3%
169	4%	926.40	100%	926.40	24,480	$11,568	$14,930	$0	$13,903	$16,681	$0	$1,751	12%
170	54%	988.40	100%	988.40	386,240	$37,230	$39,167	$0	$39,912	$36,283	$3,630	($2,884)	-7%

1 **MOHAVE ELECTRIC COOPERATIVE, INC.**
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3 **COMPARISONS - 2010 USAGE**
4 **LC&I TIME OF USE (EXISTING CUSTOMERS)**
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8						Existing LC&I Rate			Staff's Proposed Rate			TOU Rate Change	
9		Estimated		NCP				TOU			TOU		
10	L.F.	On-Peak *		kW	kWh	Standard	TOU	Savings	Standard	TOU	Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$175.00	$189.00		$119.00	170%
13	On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
14	Demand Charge, per NCP kW					$9.75			$10.89	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070031	$0.051754		$0.01	26%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.02)	-100%
17													
18													
171	48%	1,586.80	100%	1,586.80	550,360	$54,432	$57,862	$0	$57,923	$53,268	$4,654	($4,594)	-8%
172	31%	1,394.80	100%	1,394.80	315,600	$36,299	$40,084	$0	$39,391	$38,394	$997	($1,691)	-4%
173	19%	1,011.60	100%	1,011.60	138,600	$19,813	$22,972	$0	$21,598	$22,473	$0	($499)	-2%
174	28%	561.60	100%	561.60	114,480	$13,685	$15,267	$0	$14,833	$14,650	$183	($617)	-4%
175	Correction	-	100%		(153,600)	($10,289)	($9,586)	$0	($9,882)	($7,004)	$0	$2,581	-27%
176	Total	64,343.36		64,343.36	17,180,160	$1,842,672	$2,005,274	$0	$1,967,193	$1,870,592	$119,499	($134,682)	-7%
177													
178	Primary												
179	51%	3,924.00	100%	3,924.00	1,459,200	$140,170	$148,202	$0	$145,551	$132,134	$13,417	($16,068)	-11%
180	75%	11,952.00	100%	11,952.00	6,542,280	$570,523	$585,379	$0	$584,515	$505,351	$79,164	($80,028)	-14%
181	52%	1,296.00	100%	1,296.00	495,840	$47,820	$50,409	$0	$50,428	$45,857	$4,571	($4,553)	-9%
182	Total	17,172.00		17,172.00	8,497,320	$758,514	$783,991	$0	$780,495	$683,343	$97,153	($100,649)	-13%
183													
184	Transmission (Billed as TOU In Test Year - Assumed Non-TOU under new rates)												
185	78%	49,732.47	94%	53,106.00	30,204,000	$2,610,704	$2,625,974	$0	$2,493,468	$2,110,425	$383,043	($515,550)	-20%
186													
187	Substation												
188	81%	60,072.00	100%	60,072.00	35,668,800	$3,057,141	$3,119,048	$0	$2,996,496	$2,565,658	$430,837	($553,390)	-18%
189	58%	7,428.00	100%	7,428.00	3,133,200	$290,284	$303,789	$0	$287,291	$256,336	$30,956	($47,453)	-16%
190	Total	67,500.00		67,500.00	38,802,000	$3,347,426	$3,422,837	$0	$3,283,787	$2,821,994	$461,793	($600,844)	-18%
191													
192	Total Lost Revenue										$1,845,261		

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISONS - 2010 USAGE
LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Mohave's Rebuttal Rate			TOU Rate Change	
L.F.	Estimated On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
20%	-	0%	300.00	43,800	$6,029	$2,903	$3,126	$6,501	$3,311	$3,190	$407	14%
40%	30.00	10%	300.00	87,600	$9,063	$6,141	$2,921	$9,575	$6,207	$3,368	$66	1%
60%	150.00	50%	300.00	131,400	$12,096	$10,595	$1,502	$12,649	$11,174	$1,475	$579	6%
80%	300.00	100%	300.00	175,200	$15,130	$15,453	$0	$16,723	$16,831	$0	$1,378	9%
20%	-	0%	1,000.00	146,000	$19,933	$9,514	$10,419	$21,262	$10,616	$10,646	$1,102	12%
40%	100.00	10%	1,000.00	292,000	$30,045	$20,308	$9,737	$31,509	$20,271	$11,237	($37)	0%
60%	500.00	50%	1,000.00	438,000	$40,158	$35,152	$5,006	$41,756	$36,827	$4,929	$1,676	5%
80%	1,000.00	100%	1,000.00	584,000	$50,271	$51,346	$0	$52,002	$55,683	$0	$4,336	8%
20%	-	0%	5,000.00	730,000	$99,383	$47,290	$52,093	$105,609	$52,358	$53,251	$5,068	11%
40%	500.00	10%	5,000.00	1,460,000	$149,947	$101,260	$48,687	$156,844	$100,636	$56,207	($624)	-1%
60%	2,500.00	50%	5,000.00	2,190,000	$200,510	$175,480	$25,030	$208,078	$183,414	$24,664	$7,934	5%
80%	5,000.00	100%	5,000.00	2,920,000	$251,074	$256,450	$0	$259,312	$277,693	$0	$21,242	8%
20%	-	0%	10,000.00	1,460,000	$198,697	$94,510	$104,187	$211,044	$104,536	$106,507	$10,026	11%
40%	1,000.00	10%	10,000.00	2,920,000	$299,824	$202,450	$97,374	$313,512	$201,093	$112,420	($1,358)	-1%
60%	5,000.00	50%	10,000.00	4,380,000	$400,951	$350,890	$50,060	$415,981	$366,649	$49,332	$15,758	4%
80%	10,000.00	100%	10,000.00	5,840,000	$502,078	$512,830	$0	$518,450	$555,205	$0	$42,375	8%
Existing TOU Customers - 2010 Usage (Billed under Phase Three)												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,205	$20,775	$5,430	$2,972	17%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$26,995	$23,553	$3,442	$6,321	37%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,802	$23,197	$30,605	$10,197	78%
	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$107,002	$67,524	$39,477	$19,489	41%
Estimated On-Peak		100%										
Secondary												
59%	1,279.20	100%	1,279.20	554,400	$51,713	$53,971	$0	$54,877	$63,453	$0	$9,482	18%
49%	1,480.40	100%	1,480.40	531,560	$52,092	$55,209	$0	$55,455	$67,549	$0	$12,340	22%
80%	1,393.60	100%	1,393.60	809,120	$70,471	$71,992	$0	$73,994	$79,269	$0	$7,278	10%
80%	1,224.40	100%	1,224.40	713,440	$62,124	$63,448	$0	$65,270	$69,856	$0	$6,408	10%
77%	4,519.20	100%	4,519.20	2,542,320	$220,996	$226,299	$0	$229,518	$248,105	$0	$21,806	10%
86%	4,603.20	100%	4,603.20	2,873,760	$244,772	$248,872	$0	$253,691	$266,994	$0	$18,122	7%
53%	1,636.00	100%	1,636.00	634,960	$60,772	$63,998	$0	$64,398	$76,817	$0	$12,818	20%

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4 LC&I TIME OF USE (EXISTING CUSTOMERS)
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						Existing LC&I Rate			Mohave's Rebuttal Rate			TOU Rate Change	
8													
9		Estimated		NCP				TOU			TOU		
10	L.F.	On-Peak *		kW	kWh	Standard	TOU	Savings	Standard	TOU	Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
17													
18													
57	41%	996.80	100%	996.80	299,680	$31,316	$33,682	$0	$33,938	$43,255	$0	$9,573	28%
58	38%	1,225.20	100%	1,225.20	335,400	$36,017	$39,076	$0	$38,921	$51,011	$0	$11,935	31%
59	38%	1,807.20	100%	1,807.20	500,720	$53,143	$57,626	$0	$56,833	$74,519	$0	$16,892	29%
60	39%	1,523.20	100%	1,523.20	431,840	$45,603	$49,337	$0	$48,920	$63,642	$0	$14,305	29%
61	33%	1,879.20	100%	1,879.20	449,880	$50,323	$55,310	$0	$54,045	$73,835	$0	$18,525	33%
62	71%	4,768.80	100%	4,768.80	2,488,800	$219,723	$226,207	$0	$228,468	$251,919	$0	$25,712	11%
63	70%	4,732.80	100%	4,732.80	2,433,520	$215,543	$222,145	$0	$224,198	$248,195	$0	$26,050	12%
64	63%	4,004.00	100%	4,004.00	1,854,560	$168,335	$174,856	$0	$175,664	$200,019	$0	$25,163	14%
65	70%	2,143.20	100%	2,143.20	1,099,280	$97,878	$100,880	$0	$102,484	$113,437	$0	$12,557	12%
66	69%	1,264.80	100%	1,264.80	640,240	$57,518	$59,329	$0	$60,745	$67,402	$0	$8,073	14%
67	46%	1,265.60	100%	1,265.60	422,400	$42,437	$45,249	$0	$45,465	$56,448	$0	$11,199	25%
68	50%	2,374.40	100%	2,374.40	868,240	$84,129	$89,057	$0	$88,775	$107,827	$0	$18,771	21%
69	50%	2,261.60	100%	2,261.60	825,760	$80,087	$84,786	$0	$84,571	$102,745	$0	$17,959	21%
70	35%	1,838.00	100%	1,838.00	468,560	$51,215	$55,962	$0	$54,909	$73,702	$0	$17,740	32%
71	92%	2,476.48	100%	2,476.48	1,654,720	$139,250	$140,958	$0	$144,205	$149,213	$0	$8,255	6%
72	76%	2,060.80	100%	2,060.80	1,144,800	$99,737	$102,222	$0	$103,561	$112,322	$0	$10,100	10%
73	74%	2,582.40	100%	2,582.40	1,398,720	$122,901	$126,179	$0	$128,261	$139,978	$0	$13,799	11%
74	76%	1,332.80	100%	1,332.80	735,040	$64,747	$66,379	$0	$68,136	$73,951	$0	$7,573	11%
75	53%	3,433.20	100%	3,433.20	1,336,080	$126,857	$133,613	$0	$133,087	$159,011	$0	$25,398	19%
76	41%	1,130.40	100%	1,130.40	335,200	$35,079	$37,783	$0	$37,879	$48,529	$0	$10,746	28%
77	74%	1,424.00	100%	1,424.00	769,480	$68,022	$69,838	$0	$71,541	$78,065	$0	$8,227	12%
78	29%	1,298.24	100%	1,298.24	271,200	$32,283	$35,909	$0	$35,207	$49,681	$0	$13,773	38%
79	57%	3,694.96	100%	3,694.96	1,533,760	$143,102	$149,933	$0	$149,799	$175,797	$0	$25,864	17%
80	119%	194.40	100%	194.40	168,800	$13,727	$13,683	$44	$14,304	$13,934	$370	$251	2%
81	57%	921.60	100%	921.60	384,800	$36,479	$38,172	$0	$39,097	$45,582	$0	$7,410	19%
82	53%	2,798.80	100%	2,798.80	1,073,520	$102,486	$108,064	$0	$107,783	$129,238	$0	$21,173	20%
83	31%	1,244.00	100%	1,244.00	280,280	$32,383	$35,764	$0	$35,256	$48,724	$0	$12,960	36%
84	45%	1,312.00	100%	1,312.00	428,920	$43,341	$46,297	$0	$46,425	$57,986	$0	$11,690	25%
85	41%	2,264.00	100%	2,264.00	681,440	$70,114	$75,483	$0	$74,468	$95,537	$0	$20,054	27%
86	62%	1,076.80	100%	1,076.80	485,920	$44,996	$46,809	$0	$47,876	$54,724	$0	$7,916	17%
87	64%	1,270.12	100%	1,270.12	592,360	$54,253	$56,303	$0	$57,442	$65,128	$0	$8,825	16%
88	60%	1,339.20	100%	1,339.20	583,360	$54,304	$56,654	$0	$57,559	$66,477	$0	$9,823	17%
89	48%	1,795.20	100%	1,795.20	631,520	$62,085	$65,925	$0	$65,883	$80,795	$0	$14,870	23%
90	26%	1,311.24	100%	1,311.24	249,840	$30,930	$34,703	$0	$33,849	$48,944	$0	$14,242	41%
91	55%	1,254.80	100%	1,254.80	500,640	$47,751	$50,164	$0	$50,839	$60,108	$0	$9,944	20%
92	55%	4,298.40	100%	4,298.40	1,710,240	$161,209	$169,495	$0	$168,726	$200,426	$0	$30,931	18%
93	58%	2,176.80	100%	2,176.80	914,160	$85,383	$89,359	$0	$89,856	$104,987	$0	$15,628	17%
94	68%	1,913.60	100%	1,913.60	952,720	$85,488	$88,300	$0	$89,709	$100,066	$0	$11,765	13%

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4 LC&I TIME OF USE (EXISTING CUSTOMERS)
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						Existing LC&I Rate			Mohave's Rebuttal Rate			TOU Rate Change	
8–10	L.F.	Estimated On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
17													
18													
95	57%	3,940.00	100%	3,940.00	1,645,200	$153,210	$160,450	$0	$160,276	$187,802	$0	$27,352	17%
96	72%	1,972.00	100%	1,972.00	1,035,360	$91,781	$94,434	$0	$96,142	$105,752	$0	$11,318	12%
97	28%	1,599.20	100%	1,599.20	332,480	$39,461	$43,936	$0	$42,770	$60,618	$0	$16,682	38%
98	73%	1,786.40	100%	1,786.40	951,800	$84,184	$86,524	$0	$88,266	$96,702	$0	$10,178	12%
99	60%	1,177.60	100%	1,177.60	513,600	$47,896	$49,960	$0	$50,912	$58,747	$0	$8,788	18%
100	41%	1,767.60	100%	1,767.60	528,480	$54,679	$58,887	$0	$58,352	$74,884	$0	$15,997	27%
101	58%	2,883.60	100%	2,883.60	1,224,840	$113,794	$118,997	$0	$119,322	$139,073	$0	$20,076	17%
102	56%	5,476.00	100%	5,476.00	2,238,800	$209,301	$219,583	$0	$218,588	$257,767	$0	$38,184	17%
103	49%	1,643.20	100%	1,643.20	584,160	$57,323	$60,810	$0	$60,911	$74,445	$0	$13,636	22%
104	26%	2,480.40	100%	2,480.40	469,320	$57,531	$64,683	$0	$61,926	$90,494	$0	$25,810	40%
105	41%	1,113.60	100%	1,113.60	331,680	$34,671	$37,328	$0	$37,450	$47,913	$0	$10,585	28%
106	14%	686.40	100%	686.40	72,360	$11,914	$14,157	$0	$13,044	$22,087	$0	$7,930	56%
107	19%	1,121.08	100%	1,121.08	158,040	$22,367	$25,847	$0	$24,469	$38,460	$0	$12,613	49%
108	54%	1,704.00	100%	1,704.00	669,200	$63,806	$67,131	$0	$67,538	$80,315	$0	$13,184	20%
109	34%	1,952.00	100%	1,952.00	480,080	$53,125	$58,246	$0	$56,954	$77,255	$0	$19,009	33%
110	55%	1,204.00	100%	1,204.00	480,160	$45,837	$48,153	$0	$48,851	$57,751	$0	$9,598	20%
111	22%	271.04	100%	271.04	43,538	$5,868	$6,685	$0	$6,519	$9,802	$0	$3,117	47%
112	0%	90.00	100%	90.00	200	$961	$1,298	$0	$1,165	$2,537	$0	$1,239	95%
113	74%	7,430.40	100%	7,430.40	4,032,000	$352,563	$361,960	$0	$365,627	$399,081	$0	$37,121	10%
114	73%	9,698.40	100%	9,698.40	5,163,840	$453,073	$465,791	$0	$469,650	$515,254	$0	$49,462	11%
115	51%	1,256.80	100%	1,256.80	463,680	$45,211	$47,800	$0	$48,267	$58,298	$0	$10,498	22%
116	50%	1,598.40	100%	1,598.40	578,880	$56,521	$59,863	$0	$60,055	$73,011	$0	$13,148	22%
117	78%	1,464.80	100%	1,464.80	837,840	$73,155	$74,810	$0	$76,781	$82,573	$0	$7,763	10%
118	53%	353.88	100%	353.88	136,920	$13,284	$13,984	$0	$14,321	$17,027	$0	$3,043	22%
119	52%	7,406.40	100%	7,406.40	2,785,920	$266,019	$281,034	$0	$277,912	$335,676	$0	$54,643	19%
120	30%	716.80	100%	716.80	158,960	$18,839	$20,799	$0	$21,027	$28,863	$0	$8,064	39%
121	3%	3,231.20	100%	3,231.20	75,120	$37,547	$49,320	$0	$42,398	$90,214	$0	$40,894	83%
122	12%	774.00	100%	774.00	69,840	$12,804	$15,387	$0	$14,342	$24,785	$0	$9,398	61%
123	55%	118.00	100%	118.00	47,600	$4,518	$4,742	$0	$4,795	$5,656	$0	$914	19%
124	49%	1,656.00	100%	1,656.00	587,040	$57,647	$61,169	$0	$61,252	$74,924	$0	$13,755	22%
125	40%	2,059.20	100%	2,059.20	607,440	$62,992	$67,931	$0	$67,054	$86,467	$0	$18,536	27%
126	8%	1,350.84	100%	1,350.84	79,400	$19,510	$24,212	$0	$22,316	$41,390	$0	$17,178	71%
127	43%	1,880.00	100%	1,880.00	586,600	$59,801	$64,164	$0	$63,649	$80,744	$0	$16,580	26%
128	60%	5,217.44	100%	5,217.44	2,291,360	$210,421	$219,492	$0	$219,474	$253,672	$0	$34,180	16%
129	60%	2,221.00	100%	2,221.00	980,680	$90,422	$94,259	$0	$95,004	$109,491	$0	$15,233	16%
130	54%	2,441.60	100%	2,441.60	967,840	$91,683	$96,406	$0	$96,494	$114,598	$0	$18,191	19%
131	44%	3,156.80	100%	3,156.80	1,015,120	$101,931	$109,120	$0	$107,565	$135,632	$0	$26,512	24%
132	49%	1,095.76	100%	1,095.76	390,240	$38,554	$40,875	$0	$41,367	$50,398	$0	$9,523	23%

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8						Existing LC&I Rate			Mohave's Rebuttal Rate			TOU Rate Change	
9		Estimated		NCP				TOU			TOU		
10	L.F.	On-Peak *		kW	kWh	Standard	TOU	Savings	Standard	TOU	Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
17													
18													
133	46%	1,324.40	100%	1,324.40	449,240	$44,870	$47,778	$0	$47,986	$59,334	$0	$11,555	24%
134	63%	312.28	100%	312.28	143,160	$13,801	$14,316	$0	$15,533	$17,517	$0	$3,201	22%
135	28%	548.60	100%	548.60	113,200	$13,680	$15,218	$0	$15,117	$21,271	$0	$6,052	40%
136	45%	996.76	100%	996.76	330,760	$33,469	$35,691	$0	$36,119	$44,820	$0	$9,128	26%
137	31%	3,238.64	100%	3,238.64	726,160	$82,714	$91,533	$0	$88,172	$123,208	$0	$31,675	35%
138	64%	2,014.00	100%	2,014.00	937,600	$85,349	$88,608	$0	$89,561	$101,742	$0	$13,135	15%
139	12%	113.60	100%	113.60	9,600	$1,843	$2,225	$0	$2,080	$3,626	$0	$1,402	63%
140	Correction	-	100%		(610,240)	($42,198)	($39,403)	$0	($42,654)	($30,565)	$0	$8,839	-22%
141	Total	189,369.16		189,369.16	76,311,058	$7,200,845	$7,561,474	$44	$7,580,602	$8,960,315	$370	$1,398,841	18%
142													
143	**Secondary Governmental**												
144	46%	1,217.60	100%	1,217.60	406,880	$40,894	$43,597	$0	$43,855	$54,414	$0	$10,817	25%
145	40%	1,855.20	100%	1,855.20	535,560	$56,024	$60,528	$0	$59,798	$77,526	$0	$16,998	28%
146	37%	5,646.40	100%	5,646.40	1,543,520	$162,804	$176,909	$0	$171,637	$227,182	$0	$50,273	28%
147	35%	5,715.20	100%	5,715.20	1,456,960	$157,480	$172,239	$0	$166,308	$224,616	$0	$52,377	30%
148	20%	1,587.20	100%	1,587.20	232,080	$32,390	$37,279	$0	$35,594	$55,247	$0	$17,967	48%
149	5%	1,248.00	100%	1,248.00	43,280	$16,006	$20,488	$0	$18,666	$36,888	$0	$16,401	80%
150	22%	1,771.20	100%	1,771.20	285,920	$37,913	$43,246	$0	$41,367	$62,758	$0	$19,512	45%
151	58%	1,186.40	100%	1,186.40	503,600	$47,289	$49,432	$0	$50,305	$58,473	$0	$9,041	18%
152	30%	1,023.60	100%	1,023.60	225,000	$26,405	$29,213	$0	$28,987	$40,191	$0	$10,978	38%
153	28%	2,095.92	100%	2,095.92	433,800	$51,322	$57,195	$0	$55,266	$78,677	$0	$21,482	38%
154	28%	1,768.00	100%	1,768.00	356,800	$42,792	$47,788	$0	$46,307	$66,245	$0	$18,458	39%
155	39%	3,160.00	100%	3,160.00	911,000	$94,750	$102,428	$0	$100,292	$130,470	$0	$28,042	27%
156	32%	3,054.00	100%	3,054.00	718,200	$80,363	$88,526	$0	$85,512	$117,992	$0	$29,466	33%
157	31%	2,018.60	100%	2,018.60	457,800	$52,231	$57,704	$0	$56,112	$77,870	$0	$20,166	35%
158	29%	2,812.00	100%	2,812.00	596,800	$69,594	$77,406	$0	$74,468	$105,564	$0	$28,158	36%
159	33%	2,516.00	100%	2,516.00	614,600	$67,941	$74,561	$0	$72,509	$98,741	$0	$24,180	32%
160	35%	1,354.44	100%	1,354.44	341,760	$37,718	$41,232	$0	$40,768	$54,702	$0	$13,470	33%
161	51%	1,436.40	100%	1,436.40	538,200	$52,123	$55,045	$0	$55,444	$66,736	$0	$11,691	21%
162	57%	1,936.80	100%	1,936.80	804,480	$75,446	$79,025	$0	$79,557	$93,202	$0	$14,178	18%
163	65%	3,676.80	100%	3,676.80	1,742,400	$157,376	$163,184	$0	$164,245	$186,835	$0	$22,651	14%
164	47%	2,390.40	100%	2,390.40	827,040	$81,431	$86,607	$0	$86,057	$106,169	$0	$19,561	23%
165	7%	3,295.20	100%	3,295.20	160,560	$44,089	$55,711	$0	$49,089	$96,188	$0	$40,477	73%
166	45%	1,655.20	100%	1,655.20	537,760	$54,226	$57,970	$0	$57,785	$72,421	$0	$14,450	25%
167	96%	2,008.80	100%	2,008.80	1,413,960	$118,364	$119,421	$0	$123,113	$125,786	$0	$6,365	5%
168	11%	1,444.40	100%	1,444.40	116,040	$22,960	$27,845	$0	$25,901	$45,676	$0	$17,831	64%
169	4%	926.40	100%	926.40	24,480	$11,568	$14,930	$0	$13,860	$27,554	$0	$12,624	85%
170	54%	988.40	100%	988.40	386,240	$37,230	$39,167	$0	$39,922	$47,397	$0	$8,229	21%

Row	L.F.	Estimated On-Peak *		NCP kW	kWh	Existing LC&I Rate Standard	Existing LC&I Rate TOU	Existing LC&I Rate TOU Savings	Mohave's Rebuttal Rate Standard	Mohave's Rebuttal Rate TOU	Mohave's Rebuttal Rate TOU Savings	TOU Rate Change $	TOU Rate Change %
1	MOHAVE ELECTRIC COOPERATIVE, INC.												
2													
3	COMPARISONS - 2010 USAGE												
4	LC&I TIME OF USE (EXISTING CUSTOMERS)												
5													
6													
7													
8													
9													
10													
11													
12	Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
16	PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
17													
18													
171	48%	1,586.80	100%	1,586.80	550,360	$54,432	$57,862	$0	$57,927	$71,271	$0	$13,410	23%
172	31%	1,394.80	100%	1,394.80	315,600	$36,299	$40,084	$0	$39,370	$54,437	$0	$14,352	36%
173	19%	1,011.60	100%	1,011.60	138,600	$19,813	$22,972	$0	$21,568	$34,265	$0	$11,293	49%
174	28%	561.60	100%	561.60	114,480	$13,685	$15,267	$0	$14,822	$21,134	$0	$5,867	38%
175	Correction	-	100%		(153,600)	($10,289)	($9,586)	$0	($9,905)	($6,839)	$0	$2,747	-29%
176	Total	64,343.36		64,343.36	17,180,160	$1,842,672	$2,005,274	$0	$1,966,604	$2,608,788	$0	$603,514	30%
177													
178	Primary												
179	51%	3,924.00	100%	3,924.00	1,459,200	$140,170	$148,202	$0	$145,578	$176,234	$0	$28,031	19%
180	75%	11,952.00	100%	11,952.00	6,542,280	$570,523	$585,379	$0	$584,915	$637,040	$0	$51,661	9%
181	52%	1,296.00	100%	1,296.00	495,840	$47,820	$50,409	$0	$50,439	$60,331	$0	$9,922	20%
182	Total	17,172.00		17,172.00	8,497,320	$758,514	$783,991	$0	$780,932	$873,605	$0	$89,614	11%
183													
184	Transmission (Billed as TOU in Test Year - Assumed Non-TOU under new rates)												
185	78%	49,732.47	94%	53,106.00	30,204,000	$2,610,704	$2,625,974	$0	$2,495,286	$2,618,935	$0	($7,039)	0%
186													
187	Substation												
188	81%	60,072.00	100%	60,072.00	35,668,800	$3,057,141	$3,119,048	$0	$2,998,827	$3,197,574	$0	$78,526	3%
189	58%	7,428.00	100%	7,428.00	3,133,200	$290,284	$303,789	$0	$287,394	$336,049	$0	$32,260	11%
190	Total	67,500.00		67,500.00	38,802,000	$3,347,426	$3,422,837	$0	$3,286,221	$3,533,623	$0	$110,786	3%
191													
192	Total Lost Revenue										$370		

Line						Existing LC&I Rate			Mohave Proposed Rate			TOU Rate Change	
1	**MOHAVE ELECTRIC COOPERATIVE, INC.**												
2													
3	**COMPARISONS - 2010 USAGE**												
4	**LC&I TIME OF USE (EXISTING CUSTOMERS)**												
5													
6													
7													
8						Existing LC&I Rate			Mohave Proposed Rate			TOU Rate Change	
9				NCP				TOU			TOU		
10	L.F.	On-Peak *		kW	kWh	Standard	TOU	Savings	Standard	TOU	Savings	$	%
11													
12	Customer Charge					$70.00	$70.00		$170.00	$175.00		$105.00	150%
13	On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
14	Demand Charge, per NCP kW					$9.75			$10.75	$2.99		$2.99	
15	Energy Charge, per kWh					$0.045580	$0.041000		$0.072288	$0.053276		$0.012276	30%
16	PPCA Factor					$0.023685	$0.023685		($0.001850)	($0.001850)		($0.025535)	-108%
17													
18													
19	TOU Customers - 2010 Usage												
20	33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,135	$20,874	$5,261	$3,071	17%
21	20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$26,871	$23,564	$3,307	$6,332	37%
22	7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,470	$23,007	$30,463	$10,008	77%
23	1%	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$106,476	$67,445	$39,031	$19,410	40%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISONS - 2010 USAGE
LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Staff's Proposed Rate			TOU Rate Change	
L.F.	On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$175.00	$189.00		$119.00	170%
On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
Demand Charge, per NCP kW					$9.75			$10.89	$3.08		$3.08	
Energy Charge, per kWh					$0.045580	$0.041000		$0.070031	$0.051754		$0.01	26%
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.02)	-100%
TOU Customers - 2010 Usage												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,216	$18,240	$7,977	$436	2%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$27,028	$19,177	$7,851	$1,945	11%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,956	$22,949	$31,008	$9,949	77%
1%	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$107,201	$60,365	$46,836	$12,330	26%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISONS - 2010 USAGE
LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Mohave's Rebuttal Rate Phase 1			TOU Rate Change From Existing	
L.F.	On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
On Peak Demand Charge, per on peak kW						$13.50			$11.11		($2.39)	-18%
Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
TOU Customers - 2010 Usage												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,205	$17,864	$8,341	$61	0%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$26,995	$18,835	$8,160	$1,603	9%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,802	$22,612	$31,190	$9,612	74%
1%	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$107,002	$59,311	$47,691	$11,276	23%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISONS - 2010 USAGE
LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Mohave's Rebuttal Rate Phase 2			TOU Rate Change From Existing	
L.F.	On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
On Peak Demand Charge, per on peak kW						$13.50			$16.71		$3.21	24%
Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
TOU Customers - 2010 Usage												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,205	$19,235	$6,970	$1,432	8%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$26,995	$21,057	$5,938	$3,825	22%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,802	$22,887	$30,915	$9,888	76%
1%	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$107,002	$63,179	$43,822	$15,144	32%

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISONS - 2010 USAGE
LC&I TIME OF USE (EXISTING CUSTOMERS)

					Existing LC&I Rate			Mohave's Rebuttal Rate Phase 3			TOU Rate Change From Existing	
L.F.	On-Peak *		NCP kW	kWh	Standard	TOU	TOU Savings	Standard	TOU	TOU Savings	$	%
Customer Charge					$70.00	$70.00		$175.00	$180.00		$110.00	157%
On Peak Demand Charge, per on peak kW						$13.50			$23.00		$9.50	70%
Demand Charge, per NCP kW					$9.75			$10.84	$3.08		$3.08	
Energy Charge, per kWh					$0.045580	$0.041000		$0.070184	$0.050381		$0.009381	23%
PPCA Factor					$0.023685	$0.023685		$0.000000	$0.000000		($0.023685)	-100%
TOU Customers - 2010 Usage												
33%	244.80	28%	884.00	214,400	$24,099	$17,803	$6,296	$26,205	$20,775	$5,430	$2,972	17%
20%	396.80	33%	1,192.00	170,600	$24,279	$17,232	$7,047	$26,995	$23,553	$3,442	$6,321	37%
7%	49.20	1%	3,637.20	179,880	$48,622	$13,000	$35,622	$53,802	$23,197	$30,605	$10,197	78%
1%	690.80	12%	5,713.20	564,880	$97,000	$48,035	$48,965	$107,002	$67,524	$39,477	$19,489	41%

MOHAVE ELECTRIC COOPERATIVE, INC

DEVELOPMENT OF PHASE-IN RATES FOR EXISTING LC&I TOU CUSTOMERS

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Large C&I TOU - REBUTTAL PHASE ONE (2012)							
Service Charge (12 Month Sum)	31	0.00	180.00	180.00	0	5,580	5,580
On-Peak Demand	690.80	11.11	0.00	11.11	7,675	0	7,675
NCP kW	5,713.20	0.00	3.08	3.08	0	17,597	17,597
Energy Charge per kWh	564,880	0.045261	0.005120	0.050381	25,567	2,892	28,459
Base Revenue					33,242	26,069	59,311
PPCA Revenue					0	0	0
Total Revenue					33,242	26,069	59,311
Existing Revenue							48,035
Percentage Change from Existing							23%
Large C&I TOU - REBUTTAL PHASE TWO (2013)							
Service Charge (12 Month Sum)	31	0.00	180.00	180.00	0	5,580	5,580
On-Peak Demand	690.80	16.71	0.00	16.71	11,543	0	11,543
NCP kW	5,713.20	0.00	3.08	3.08	0	17,597	17,597
Energy Charge per kWh	564,880	0.045261	0.005120	0.050381	25,567	2,892	28,459
Base Revenue					37,110	26,069	63,179
PPCA Revenue					0	0	0
Total Revenue					37,110	26,069	63,179
Existing Revenue							48,035
Percentage Change from Existing							32%
Percentage Change from Prior Phase							7%
Large C&I TOU - REBUTTAL PHASE THREE (2014)							
Service Charge (12 Month Sum)	31	0.00	180.00	180.00	0	5,580	5,580
On-Peak Demand	690.80	23.00	0.00	23.00	15,888	0	15,888
NCP kW	5,713.20	0.00	3.08	3.08	0	17,597	17,597
Energy Charge per kWh	564,880	0.045261	0.005120	0.050381	25,567	2,892	28,459
Base Revenue					41,455	26,069	67,524
PPCA Revenue					0	0	0
Total Revenue					41,455	26,069	67,524
Existing Revenue							48,035
Percentage Change from Existing							41%
Percentage Change from Prior Phase							7%

EFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01750A-11-0136

EXHIBIT
MEC-4

REJOINDER TESTIMONY OF

MICHAEL W. SEARCY

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

MARCH 30, 2012

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REJOINDER TESTIMONY OF
MICHAEL W. SEARCY
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

SUMMARY OF REJOINDER TESTIMONY

Mr. Searcy is a Managing Consultant for CH Guernsey & Company, the consulting firm retained by Mohave Electric Cooperative, Incorporated ("Mohave") to assist in the preparation and processing of its rate application. In his rejoinder testimony Mr. Searcy emphasizes the many areas of agreement between Staff and MEC and demonstrates the reasonableness of and why the Commission should adopt the following positions supported by the Mohave Board (the elected representatives of Mohave's member/customers):

1. A $16.50 per month residential customer charge, to ensure year round residents are not subsidizing part time and transient customers and eliminate the need for complex decoupling adjustors by pricing electricity more closely to how costs are incurred.
2. Allocate revenues among rate classes on cost of service principles, tempered by understandability, equity and minimizing customer impact, but rejecting Staff's artificial cap for the residential class to the overall rate increase percentage, which effectively freezes existing inequities.
3. Adoption or planned phase-in of an appropriately designed rate for the 3 existing Large Commercial & Industrial Time of Use Rate to eliminate the subsidy they are currently receiving and would continue to receive, albeit at a lesser level, under Staff's proposal to create a frozen rate for these 3 customers.
4. Immediate implementation of Prepaid Service, to address the needs of Mohave's members/customers, without stripping Mohave of the financial protections associated with its standard deposit policies.
5. Inclusion of up to 50% of transformer costs as part of the line-extension allowance for individual customers and application of Mohave's existing line extension policy in a manner consistent with the notice prospective members receive when they request a written estimate.
6. Leaving the decision whether and when to file a rate case in the hands of Mohave's Board – the elected representatives of its members/customers.

Mr. Searcy also explains impacts on the Income Statement and PPCA base cost due to differences with Staff relating to the treatment of power purchase related consulting, legal and staff costs and of third party sales discussed by Mr. Carl Stover.

1. INTRODUCTION

Q. Please state your name, your employer and your position.

A. My name is Michael W. Searcy and I am employed by C. H. Guernsey & Company ("Guernsey"). My current position is Managing Consultant. I have previously presented Direct, Supplemental and Rebuttal Testimony in this matter on behalf of Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative").

Q. Were all of the supporting schedules attached to your testimony prepared by you or under your direction?

A. Yes.

2. PURPOSE OF REJOINDER TESTIMONY

Q. What is the purpose of your rejoinder testimony?

A. My Rejoinder testimony will address Surrebuttal testimony submitted by Staff on the following issues:

1. Rate Class Rate Designs
2. Rate Class Revenue Requirement
3. Revenue, Expenses and Revenue Requirement
4 Line Extension Policy and Prepaid Metering

Q. How is your testimony organized?

A. I first emphasize the areas of general agreement between Staff and Mohave and then proceed to discuss the following areas of disagreement: a) the residential customer charge, b) allocation of revenues among rate classes, c) the Large Commercial & Industrial time-of-use (LC&I TOU) rate, d) the impact on the income statement and PPCA base cost from the different positions on recovery of power purchase related consulting, legal and staff expenses and third party sales (i.e., through the PPCA or base rates), e) the process for implementing a prepaid service program, f) including up to 50% of the transformer costs as part of the line-extension allowance for individual customers, g) treatment of customers with written estimates under the existing line extension policy and h) finally, whether the Commission or the Mohave

Board of Directors should determine when Mohave is to file its next request for rate relief.

3. AREAS OF AGREEMENT BETWEEN STAFF AND MOHAVE

Q. After submittal of Staff's Surrebuttal what is your conclusion relating to the relative positions of Staff and the Cooperative in this case?

A. Mohave and Staff agree on most of the issues the Commission must decide as part of this proceeding as reflected in my Rejoinder Schedule MWS-5, including:

- Adjusted test year rate base of $48,083,871.
- Adjusted test year revenues of $76,068,006.
- Adjusted test year operating expenses of $75,523,583.
- Adjusted test year return of $544,423 and operating margins of ($1,776,305).
- A recommended revenue increase of $3,061,529 or 4.025%.

Staff and Mohave also agree:

- The Cost of Service Study ("COSS") submitted by Mohave is a traditional fully allocated COSS and Mohave's proposed functionalization, classification, and allocation techniques used in its COSS fall within the bounds of standard industry practice. I note, the procedures and methodology used in Mohave's COSS have been previously approved by the Commission (e.g., the last Trico Electric Cooperative (Docket No. E-01461A-08-0430) and Sulphur Springs Valley Electric Cooperative (Docket No. E-01575A-08-0328) rate cases), and are approved by Staff in the pending Navopache Electric Cooperative, Inc. rate case (Docket No. E-01787A-11-0186).
- The rate designs proposed by Mohave, as adjusted by Staff, are reasonable and should be approved, subject to the residential customer charge, capping the revenue increase for the residential customers and creating a unique rate for the 3 existing Large C&I TOU class increase as I discuss below.
- Mohave's proposed service charges, as amended by Staff, are reasonable and should be approved.
- Mohave's proposed Service Policies, with the additions recommended by Staff are reasonable and should be approved, subject to the three exceptions I discuss below.

Mohave appreciates Staff's general support of its rate application.

4. RATE DESIGN

A. <u>Generally</u>

Q. Staff has suggested rate designs and rate class revenues in Surrebuttal testimony. Does Mohave agree with these rate designs and revenues?

A. Mohave and Staff substantially agree on most rate designs, except as indicated below.

Q. Are the rates included in Staff's Surrebuttal testimony and in Mohave's Rejoinder testimony identical?

A. Except as indicated below, they are substantially the same but not identical. Since, as I discuss later, Mohave and Staff recommend slightly different base power cost factors, the various energy and some demand charges are slightly different. Mohave believes that, once the base power cost issue is determined, other than where otherwise described below, the parties agree. To see the small differences, refer to <u>Mohave Rejoinder Schedules MWS-2</u>, <u>MWS-3</u> and <u>MWS-4</u>. <u>Mohave Rejoinder Schedule MWS-7</u> shows a rate-by-rate comparison between Mohave's existing, Staff's Surrebuttal, and Mohave's Rejoinder rates.

Q. In what areas do Mohave and Staff substantially agree?

A. Other than minor differences related to the base cost of power and customer charge levels, Mohave and Staff substantially agree with rate designs for Residential, Residential Time-of-Use (TOU), Residential Optional Demand, Residential Net Metering, and Small Commercial Energy rates. Other than minor differences related to the base cost of power, Mohave and Staff agree on Small Commercial Demand, Large Commercial and Industrial (LC&I) (other than LC&I TOU for existing customers), Irrigation, Lighting, and "Other Revenue." In addition, Mohave and Staff agree on the amount of difference between the standard Residential customer charge and the Residential TOU, Residential Optional Demand, Residential Net Metering, and Small Commercial Energy customer charges.

Q. In what areas does Mohave continue to disagree with Staff with regard to rate designs?

A. Mohave continues to disagree with Staff in the following areas:

1) The Residential customer-related cost of providing service and the proposed Residential Customer Charge amount (affecting other related Customer Charges as well)

2) The revenue responsibility for the individual rate classes

3) The LC&I TOU rate for <u>existing</u> customers only

B. <u>The Proposed $16.50 Residential Customer Charge Is Reasonable.</u>

Q. In what areas do Staff and Mohave agree with regard to residential rates?

A. Staff and Mohave substantially agree with regard to all Residential rate design components other than the customer charge. Of course, the actual energy charges to be applied will depend on the final customer charges approved, but Staff and Mohave are in agreement as to the basic rate design structure, other than customer charges.

Q. How does the COSS provide information needed to determine the appropriate Customer Charge?

A. Since Mohave bases its customer charge in large part on the results of its COSS, it is important to review the findings of that study with regard to customer-related costs and recovery. One basic purpose of any COSS is to determine how costs are incurred. To the extent changes in rates move a cooperative closer to recovering costs in manner similar to how costs are incurred, rates are generally fairer to customers and allow a cooperative to decouple its rates so it will see less negative financial impact from promoting renewables, energy efficiency and conservation, as well as less negative financial impact from other issues that affect energy consumption such as weather and economic down-turns.

Rates are fairer because customers pay for costs they cause to be incurred (rather than one group of customers subsidizing other customers), and rates are more fully decoupled, without the need for complex annual adjustor mechanisms, because fixed customer-related costs of providing service are not recovered through variable energy charges to the same extent.

Mohave recognizes that moving its customer charge closer to its customer-related cost of providing service is one factor among others to be considered when designing rates. But it is an important factor, particularly since it is also a PURPA standard. Another important factor is reducing customer impact, and Mohave's elected Board considered carefully customer impact when deciding on its proposed $16.50 per month residential customer charge. The proposed customer charge is less than its monthly residential customer-related cost of providing service ($18.56), and far less than the total monthly residential cost of providing wires service ($30.00). Mohave further moderated the impact of its proposed customer charge by requesting an inclining block rate design and by the small size of the total rate increase requested. (For Mohave's Components of Expense, *see*, Mohave's 3/30/11 Rate Application, Schedule G-6.0, page 1 of 6.)

Mohave and Staff agree that Mohave has used standard industry practice in developing all aspects of the COSS individually developed for Mohave. (Direct testimony of Bentley Erdwurm, page 9, lines 7 – 9)

Staff says its suggested Surrebuttal Residential customer charge of $13.50 was "driven by a costing methodology restricting the customer-related classification to metering, meter-reading, the service drop, billing and customer service." (Surrebuttal testimony of Bentley Erdwurm, page 2, lines 22 – 25) In addition it says that, "utilities – both those with more dense territories and those with less dense territories – typically view rate stability as desirable, that higher residential customer charges typically promote rate stability, and that higher residential customer charges may be supported, rightly or wrongly, through classifying as customer-related a portion of poles, lines and transformers." (Surrebuttal testimony of Bentley Erdwurm, page 4, lines 9 – 15)

Mohave's COSS was individually developed for Mohave using industry standard methods previously used by other Arizona cooperatives and approved by Staff and the Commission. It allocates a portion of distribution wires cost related to minimum sized distribution facilities required to serve any customer, no matter how small. Given how Mohave's COSS was developed, the Cooperative believes there is no question that a portion of the cost of providing minimum system service to every customer no matter how small, is <u>driven</u> by customer-related factors. Staff argues Mohave should not be permitted to <u>recover</u> what Mohave's COSS has identified as fixed customer-related costs through customer charges. Mohave believes this reasoning is incorrect and inconsistent with the Commission's determination in Decision No. 71230, dated August 6, 2009 (where the Commission expressly recognized that customer service costs "includes ***the customer component of distribution line expense, a portion of the transformer expense,*** [in addition to] the meter and service drop expense and meter reading and customer records expenses." Decision at page 7, lines 17-20 (emphasis added).

In my Rebuttal testimony, I discussed the fact that electric cooperatives, including Mohave, serve rural areas. The purpose of this discussion was to indicate that every cooperative incurs costs in providing minimum system service to every customer, no matter how small. The magnitude of the impact of adopting Staff's recommended customer charge treatment is greater in rural areas with especially low line density, but the same issue exists for all service areas, both urban and rural.

I prepare individual COSS analysis using industry standard methods for electric cooperatives located in jurisdictions across the country. Mohave's customer-related cost of providing service ($18.56) as identified by its COSS is low by cooperative standards. It is not uncommon for more heavily rural systems to see customer-related cost of $20 - $35 or higher. Mohave's cost is somewhat lower in large part because it has somewhat more urban service area. Mohave does not ask for its customer charge to be set based on the average rural electric cooperative customer-related cost of providing service, but based on its individually developed customer-related cost of providing service developed through its COSS procedure.

Q. Is Mohave's COSS methodology different in some way?

A. No. Mohave's COSS follows the Commission's determination in Decision No. 71230. Staff has provided no evidentiary support for the Commission's rejection or modification of this earlier determination.

In Surrebuttal, Staff indicates that this cited decision, "applied to TRICO, not to Mohave and not to other utilities." The Commission's determination, while applied in a rate case involving TRICO, is not limited to TRICO in any way. Rather the Commission is making a general determination as to what is included in customer service costs for COSS purposes. Staff does not present any evidence as to why the same industry standard allocation methods used for TRICO would not apply to Mohave in this case because none exist. The Cooperative believes its COSS methodologies, the same ones approved by the Commission in Decision No. 71230, are appropriate to use in this case.

Q. According to Staff, are there other reasons for not accepting Mohave's COSS determination of the customer-related cost of providing service?

A. Staff states that, "given that higher customer charges may have adverse bill impacts on bills for 'basic needs' levels, and may be contrary to providing incentives supporting the prudent use of energy, Staff contends that the default position in future Mohave rate cases should be that no portion of poles, lines and transformers is classified as customer-related without some study supporting the magnitude of customer component." (Surrebuttal testimony of Bentley Erdwurm, page 3, line 23 – page 4, line 2)

Mohave believes recovering its fixed costs through variable energy charges distorts the price signal to customers. The best method of promoting energy efficiency through decoupling is to minimize the recovery of fixed cost through variable energy charges. Other complex decoupling mechanisms further distort the price signal and may encourage investment in technologies in the name of energy efficiency by distorting recovery of the cost of providing wires service. The cost of wires service, however, is not reduced by conservation efforts and the anticipated savings to the cooperative and ultimately the member-consumer may never materialize, all of which run counter to the PURPA decoupling standard. Mohave's proposed rate certainly provides a strong pricing signal promoting energy efficiency through its proposed inclining block rate.

Moreover, Mohave's COSS <u>is</u> a "study supporting the magnitude of the customer component." If Staff is suggesting additional studies, it has provided no examples of the type of study it seeks and I am unaware of any beyond the cost allocation included in the COSS already submitted.

Finally, Mohave agrees with Staff that movement toward the results of a COSS should be tempered if they will have significant bill impacts. However, Mohave's rates will have very limited impact on customers with average or median usage. Under Mohave's Rejoinder rates, a residential customer with average usage of 860 kWh per month will see a rate decrease of $0.55 or 0.54%. A customer with median usage of 637 kWh per month will see a rate decrease of $0.15 or 0.19%. <u>See Mohave Rejoinder Schedule MWS-8</u>. As shown on the Schedule, low use customers will not see increases greater than $0.28 per month unless their monthly usage is less than 400 kWh per month. It is unlikely that many customers who actually occupy their residence for the full month will experience monthly usage at or below 400 kWh.

Q. Who will Staff's proposed customer charge benefit and who will it hurt?

A. The biggest benefactors of Staff's rate design are minimum usage, part-time and transitory residents whose usage during a billing cycle is artificially low because the residence is unoccupied for all or much of the month. In contrast, full-time residents and other rate classes will be burdened by higher energy rates and/or higher relative rates of return in order to make up the lost revenue that should be allocated to the customer charge. Beyond this basic fairness issue, Mohave is also harmed by the lack of revenue stability inherent in Staff's proposed rate design, which in turn can lead to additional and more frequent rate increases for all of its member/customers.

Q. What is Mohave's recommendation with regard to the COSS?

A. Mohave continues to recommend the COSS be approved as prepared and without changes, including classification of costs, and that its COSS be given appropriate consideration in determining the Residential customer charge.

Q. What is Mohave's recommendation with regard to the residential customer charge?

A. Mohave continues to propose a residential customer charge of $16.50 per month. Mohave's Rejoinder residential rate design is attached as Mohave Rejoinder Schedule MWS-7, page 1. The comparison of existing, Staff Surrebuttal and Mohave Rejoinder rates is shown as Mohave Rejoinder Schedule MWS-8.

Q. Mohave indicated in Rebuttal testimony it would be willing to phase-in its requested change in customer charge over time. Is this still the case?

A. Yes. Mohave is still willing to phase-in its proposed customer charge to reach the $16.50 customer charge level its Board of Directors deems appropriate. In Surrebuttal testimony, Staff rejected this approach, on the grounds it "would be administratively burdensome and Mohave would be required to provide notice to its customers for each rate adjustment." As the rate levels would be preapproved, there would not be any additional administrative burden beyond reprogramming its billing system with the appropriate rate and including a notice in the monthly billing statements the month before each phase goes into effect. While Mohave would prefer to avoid these costs by moving immediately to $16.50, it is willing to incur these costs to secure a properly designed rate through a single rate proceeding, rather than awaiting the next full rate case as Staff suggests.

Mohave continues to be willing to work with Staff to develop a phase-in plan leading to its proposed $16.50 customer charge over a reasonable period (two or three years), should the Commission deem Mohave's proposed customer charge change is too large in one step.

Given Staff's rejection of the phase-in, Rejoinder phase-in rates were not developed, but MWS-Rebuttal Schedule 7 shows the rate structure that would be used. MWS-Rebuttal Schedule 8 shows comparisons under the phases at different usage levels. The approach proposed by Mohave is outlined in the Rebuttal Testimony of Michael W. Searcy, page 22, lines 10 – 22.

Q. Is Mohave asking for any adder for lost revenues due to the phase-in of the customer charge?

A. No. As recognized by Staff (Surrebuttal of Mr. Erdwurm, page 2, lines 8-9), Mohave will slightly adjust the energy charge for each phase so there is no shortfall or over collection in any phase. The specific energy charges and customer charges for each phase can and should be approved when a decision is rendered, if the Commission determines that movement to $16.50 should be phased-in.

Q. Are Mohave's members supportive of the $16.50 customer charge?

A. As Mr. Carlson testified in his Rebuttal testimony, member/customers voiced support for a customer charge that recovers a substantial portion of the customer-related costs during the several member meetings Mohave held across its service area following the filing of its Application. The $16.50 customer charge was shown to customers and the rational for the charge was discussed during those meetings. No rate design objections were presented during the meetings or, to my knowledge, subsequently. Three letters have been docketed with the Commission, two by Mohave Board members in their member capacity, expressly supporting Mohave's proposed rate decoupling and opposing Mohave recovering fixed customer–related costs through energy charges. Mohave agrees with these comments. Copies of those 3 letters are provided as <u>Mohave Rejoinder Exhibit MWS-9</u>.

Q. What would the customer charges be for the Residential TOU, Residential net metering, Residential Optional Demand and Small Commercial Energy rates?

A. Staff and Mohave now agree that the customer charge for each of these rates will be $5 per month higher than whatever standard residential customer charge is ultimately set by the Commission (i.e., if $16.50 is adopted, these other charges would be $21.50).

Q. Would the Residential TOU, Residential Optional Demand, Residential Net Metering and Small Commercial Energy rates be phased-in if the standard residential rates are phased in?

A. No. Because of the costs associated with phasing in a relatively few customers, Mohave would prefer not to phase-in the customer charges for TOU and net metering residential customers. These rates are optional and customers can always choose to move to the standard rate.

C. <u>Staff's Arbitrary Cap On *Allocating* Revenue Responsibility To The Residential Class</u>.

Q. Does Staff recommend changes to Mohave's proposed revenue allocation to the various rate classes in its Surrebuttal testimony?

A. Yes. Staff continues to cap the increase in revenues for the residential class to the overall percentage increase approved for the Cooperative. See, Staff Exhibit DBE-1, showing Mohave's proposed increase to the residential rate class of 4.07% has been reduced to 4.02% by Staff (equivalent to the 4.02% total increase in revenue).

Mohave, in Rebuttal, has already outlined its opposition to a cap imposed by Staff to limit increases to a residential rate class at no more than the system average. Mohave continues to advocate rejection of such a cap. To summarize, Mohave disagrees with Staff's approach because it:

a) is arbitrary,

b) is unsupported by the record,

c) is contrary to the Public Utility Policy Act's intent to structure rates that, to the maximum extent practicable, will reflect the costs of service to each customer class,

d) ignores the minimal amount of additional revenue Mohave is proposing to shift to the residential class,

e) foregoes the opportunity to make such shifts when the overall increase request is minimal, and,

f) if followed consistently, would forever preclude closing the gap between the residential and other customer classes.

Furthermore, the best time to correct subsidies between rate classes is when over-all rate changes are small. Taking a small step now toward reducing subsidies between rate classes will result in less customer impact than waiting for some future rate case when the over-all change might be higher.

Q. Does Mohave's Cost of Service Study (COSS) support a greater increase for the residential rate class than the system average?

A. Yes. There are a variety of factors to be used in determining the rate change for each rate class, and the COSS is one important factor to be balanced among other factors. Staff's arbitrary cap would have the effect of saying that reducing subsidies between rate classes should be given NO weight. Where a COSS indicates subsidies exist between rate classes, the approved rate design should reduce such subsidies. Mohave recognizes the extent of the subsidy reduction is dependent on the various rate design criteria, goals and objectives discussed by both Staff and Mohave in this case. However, Staff has pointed to no criteria, goal or objective that will be undercut by taking the incremental step of 0.05% proposed by Mohave at this time.

Q. What is Mohave's proposal with regard to the class revenue requirement?

A. Mohave believes the proposed class revenue requirements should be as provided on the attached <u>Mohave Rejoinder Schedule 1</u>, and that the Staff recommended class rate changes shown on Schedule DBE-1 be rejected.

D. <u>A Frozen Large LC&I TOU Rate For 3 Existing Customers Is Unfair.</u>

Q. Does Mohave agree with Staff's Surrebuttal rate designs for the LC&I TOU rate?

A. Staff and Mohave substantially agree on the proposed rates for <u>new</u> LC&I TOU customers with slight variances due to the other unresolved issues in this case. Staff recognizes Mohave's proposed revision to the LC&I TOU rate "is well-reasoned and cost-based . . . [and] a huge improvement of the existing design." (Erdwurm Surrebuttal, page 9, lines 19-22). Therefore, Staff supports the Mohave proposed LC&I TOU rate for new customers. However, in order to limit the percentage increase experienced by the three customers currently on the LC&I TOU rate (Erdwurm Surrebuttal, beginning on page 9), Staff proposes they be placed on a special rate that will continue until new rates are established in Mohave's next rate case. At that time, Staff recommends the special rate be eliminated and the three customers be moved to the regular LC&I TOU rate. Such a frozen rate for the LC&I TOU customers is unnecessary and inappropriate. Mohave asks the Commission reject it.

Q. Why will the existing LC&I TOU customers receive such a high percentage rate increase?

A. The existing rate is not correctly designed. It allows these customers to shift usage out of on-peak windows and eliminate paying for both power supply related demand costs, as well as Mohave's distribution wires service costs. (Erdwurm Surrebuttal at pages 9-10, lines 22-2). The large percentage increase does not indicate that the proposed rate is too high, but rather that the existing rate is poorly designed and therefore unacceptably low for these three customers.

Q. Why does Mohave disagree with the frozen rate?

A. This concept is unfair to other members. Staff recognizes that its proposed rate for these customers "will mean that subscribers to LC&I TOU will pay too little for service relative to other customers, which is unfair to the other customers." (Erdwurm Surrebuttal, page 10, lines 11-13). These three customers currently enjoy, as identified by Mohave's COSS and shown on Schedule G-2.1, a negative relative rate of return (RROR) of -0.34. Mohave's existing residential rate class has a RROR of 0.20. RRORs greater than 1.0 provide a subsidy to other rate classes. RRORs under 1.0 receive a subsidy. Mohave's other customer classes (including residential) with higher RRORs than LC&I TOU are, therefore, subsidizing existing LC&I TOU customers. Under Mohave's proposed rates, the LC&I RROR moves to 4.11, while the LC&I TOU RROR moves to 1.74.

While there is a high percentage difference between the 27.33% increase recommended by Staff in Surrebuttal testimony and the 42.93% increase recommended by Mohave in Rejoinder testimony, the dollar difference is quite small. Mohave's increase is $20,622 and Staff's increase is $13,142. The total difference is only $7,480. Since total annual billing under existing rates is only $48,045, however, even this small difference in the amount of the increase produces high percentages.

Rather than "kick the can down the road" to the next rate case, Mohave believes there is an opportunity while the total dollar amount is low to correct the problem now.

In addition, Mohave does not agree with Staff's proposal to freeze these rates because it will result in other rate classes continuing to provide unacceptable subsidies to these three commercial customers.

Finally, Mohave believes Staff's focus on percentage change between the existing LC&I TOU rate and the proposed LC&I TOU rate is not the key factor in reviewing the proposed rate. Mohave's proposed LC&I TOU rate offers a significant savings for customers as compared to the standard LC&I rate. The three customers would be billed, under Mohave's proposed STANDARD non-TOU LC&I rate an annual total of $107,637. The same customers under Mohave's proposed Rejoinder LC&I TOU rates would only be billed $68,657 – a significant savings.

Q. Other than rate design, are there other factors at play?

A. Yes. As indicated in Rebuttal testimony, existing customers have relatively high monthly NCP kW and quite low monthly CP kW. One customer in particular had an annual load factor of only 7%. At the same time, while the customer's total monthly NCP kW was 3,637 kW, the sum of this customer's total monthly on-peak kW was 49.2 kW. So these customers have extremely atypical usage patterns.

Q. Has Mohave considered phasing in the rate change to minimize customer impact?

A. Yes. Mohave offered this option in its Rebuttal testimony. While Staff has rejected this option because the impact on Mohave's revenue is trivial and could not justify the administrative burdens of the phase-in (Erdwurm Surrebuttal, page 11, lines 4-6), Mohave remains willing to phase-in the rate changes as indicated it its Rebuttal testimony. Given Staff's rejection of Mohave's phase in offer, Rejoinder rates were not developed. MWS-Rebuttal Schedule 11 shows development of the general structure that would be used for the three phases and the general amount of revenue change between each phase and the existing rate, as well as the general revenue change between one phase and another.

5. STAFF'S REVENUE, EXPENSES AND REVENUE REQUIREMENT

Q. Does Mohave agree with Staff's recommended revenue and expenses as shown in the Surrebuttal Schedules of Crystal S. Brown?

A. As discussed above, Staff and Mohave substantially agree regarding revenues and expenses, as well as the level of rate increase that is appropriate in this case. However, the disagreement regarding treatment of power purchase related consulting, legal and staff expense results in differences in the amount of purchase power and administrative and general expenses shown on the income statements of Staff and Mohave.

While it does not affect the revenue requirement, rate designs or the income statement, and is not discussed in my testimony, Mohave does not agree with Staff's proposal to exclude third party sales (TPS) revenue as opposed to TPS power cost from its monthly PPCA calculations. This matter will instead be discussed by Mr. Stover.

Mohave also does not agree with Staff's transfer of $562,035 in expenses from purchased power to administrative and general, as shown on Staff's Surrebuttal Schedule CSB-3. As discussed more fully in the testimony of Mr. Stover, Mohave believes it has appropriately accounted for expenses incurred related to power supply as power cost expense and has appropriately recovered those expenses through its PPCA factor. Mohave proposes Staff's recommended adjustment to transfer $562,035 from purchased power expense to administrative and general expense be rejected, as shown on Mohave Rejoinder Schedule MWS-5.

This difference, however does not impact the amount of test year margins computed or the level of rate increase recommended by either Staff or Mohave. Both parties recommend a rate increase of $3,061,529, producing total revenue under proposed rates of $79,129,535, and an operating margin of $1,285,224.

6. POWER COST, PPCA BASE COST & PPCA REVENUE

Q. Does Mohave agree with Staff's recommendation that Mohave's PPCA base cost be set at $0.087701 per kWh?

A. Mohave and Staff are in general agreement regarding the calculation of the PPCA base cost. However, the disagreement regarding treatment of $562,035 in purchased power procurement expenses (Surrebuttal testimony of Jerry Mendl, page 27, lines 22 – 40), and of margins from third party sales (Surrebuttal testimony of Jerry Mendl, page 28, lines 33 – 37) results in different computations of the base purchased power cost (Surrebuttal testimony of Jerry Mendl, page 28, line 46). Should the Commission adopt the Staff recommendations on these two issues, Mohave agrees that the base cost of purchased power should be set at $0.087701, but Mohave believes the Commission should reject Staff's recommendation.

As discussed throughout the testimony of Mohave witness Carl N. Stover, the Commission should reject Staff's proposed exclusion of a) $562,035 in costs from power cost expenses and b) prospectively, both power cost and margins received from third party sales (TPS) from PPCA calculations (as opposed to its current practice of excluding only power cost). Mohave continues, therefore, to propose the base cost of purchased power be set at $0.089283. (See Mohave Rejoinder Schedule MWS-6)

7. PREPAID SERVICE NEEDS TO BE IMPLEMENTED NOW

Q. Is Staff's recommendation that Mohave pursue prepaid metering in a separate docket appropriate?

A. No. As indicated in Rebuttal testimony and separately in discussions with Staff, Mohave's customers are anxious for a prepaid service option to be implemented. Whether implemented by changes to Mohave's policies, through a tariff or both, there is no need to delay implementation for the following reasons:

1) Mohave is not proposing a separate or different rate be applied to prepaid metering customers,

2) Mohave is not proposing that prepaid metering be considered as a part of its DSM program, either as assumed reductions in usage or for cost recovery through its proposed DSM adder,

3) Mohave is proposing that it be allowed to implement prepaid metering for a single reason, to allow members with an option to putting up a security deposit, without placing the cooperative's financial position at risk,

4) Mohave's prepaid metering program would not affect revenue, and

5) Mohave members have strong support for a prepaid program to Mohave.

8. STAFF'S INAPPROPRIATE ADJUSTMENTS TO MOHAVE'S LINE EXTENSION POLICY

Q. Does Mohave agree with Staff's position on its proposed line extension policy?

A. Mohave and Staff are in agreement with all aspects of Mohave's proposed line extension policy other than 1) including the cost of transformers in the line extension allowance for customers outside of subdivisions and 2) handling prospective customers that have secured a written line extension estimate prior to entry of a decision in this case (i.e., under Mohave's current line extension policy).

Staff did not provide additional substantive testimony for its positions beyond Direct testimony, which was not persuasive as discussed in Mohave's Rebuttal testimony. Inclusion of transformer costs as part of the line extension allowance is fairer to all cooperative members. Mohave continues to request that its proposed line extension policy be approved as submitted without Staff's recommended changes, but capping any individual customer's transformer responsibility at no more than one half of the transformer's cost.

Additionally, Staff's proposal relating to the treatment of prospective customers that have secured a written line extension estimate is ambiguous and inconsistent with the documentation the prospective customers received from Mohave in conjunction with obtaining a written estimate. See MWS - Rebuttal Exhibit 2 (which holds the estimate for only 60 days). Mohave supports providing those that received written estimates within 60 days of a decision in this matter be provided the full sixty days thereafter to commence the line extension under the bid provided.

9. MOHAVE'S BOARD SHOULD DETERMINE WHEN TO MAKE RATE CASE FILINGS

Q. In Surrebuttal testimony, Staff continues to recommend the Commission order Mohave to file a rate case with a test year ending December 31, 2015, unless an earlier rate case has been filed. Does Mohave agree?

A. No. Recommendation #11, Surrebuttal testimony of Jerry Mendl, page 28, lines 8 – 14 now recognizes that, should such a filing ultimately be required, the filing date be moved from April 1, 2016 to September 1, 2016 to afford Mohave a reasonable opportunity to complete its outside audit prior to preparing and filing the case.

Mohave disagrees with Staff's recommendation that Mohave be ordered to file a rate case with a test year ending December 31, 2015 for two fundamental reasons. First, there has been no showing that Mohave's Board is incapable of making a sound business decision relating to if and when a rate case should be filed. As both the management of the utility and the elected representatives of its member/customers, the Board should be presumed to be the most appropriate body to make such decisions. There has been no evidence submitted in this proceeding to rebut such a presumption.

Second, Staff's recommendation seems driven by its desire to reduce the volume of purchased power data that has to be reviewed. (Surrebuttal testimony of Jerry Mendl, page 24, lines 13 – 14). Rate case filings (endeavors that involve substantial cost in money, time and effort) should not be driven by the amount of data that might be involved in purchased power prudency review. There are more efficient ways to minimize the burdens related to a purchased power prudency review. The key is having a clear understanding between Staff and Mohave regarding the type of documentation Mohave is required to maintain. Additionally, if Staff likewise provides appropriate feedback relating to documentation provided with monthly purchased power filings and properly maintains those documents for use in a prudency review, such reviews, regardless of the period covered, should proceed efficiently. This is especially true if Mohave is only responsible for providing documentation to the extent there are gaps in the documentation provided on a monthly basis. As part of this proceeding, Mohave has suggested discussions with Staff for the very purpose of clarifying and simplifying the purchased power record keeping and prudency review process.

It is important that the Commission understand that during the ten years since Mohave's switch to a partial requirements customers was approved, at no time did the Commission or its Staff suggest that the change subjected Mohave to the type of prudency review involved in this case. Nor was Mohave informed they were to maintain documentation on all purchased power transactions until the next rate case, even though it had been providing documentation to the Staff with its monthly purchased power filings. Now that Mohave has been informed and has been through a prudency review of power purchases, Mohave's member-selected Board of Directors will certainly consider the impacts on such reviews in determining when to file future rate cases. However, this is only but one factor to be considered. Rate filings, in their present form, are not simple proceedings and take substantial time, effort and dollars to prepare and process to a conclusion. They should be pursued when the financial needs and condition of the Cooperative warrant, not simply because a date certain has arrived.

Staff also stated that where "rates are more frequently adjusted, the odds of there being a financial emergency before MEC comes in for a rate case are reduced," (Surrebuttal testimony of Jerry Mendl, Page 24, lines 18 - 24). There is no evidence suggesting Mohave's Board would await a financial emergency before making another rate filing. Mohave's member-selected Board is best situated to determine when any future rate filing is necessary and that such decision, and the appropriate test year, should be based upon actual operational data.

As indicated in Rebuttal, Mohave does not object to filing, as a compliance item in this docket on or before April 1, 2016 a copy of its unaudited Form 7 for the calendar year 2015, together with a summary schedule containing the information contained in Schedule CSB-1 reflecting an estimate of any increase in rates the Cooperative's management anticipates might deem appropriate, unless prior thereto it has already separately docketed a rate case. Mohave and Staff can discuss at that time whether a rate filing should be made based upon actual operational data.

Staff's proposed requirement that a new rate case be filed on or before September 1, 2016 or any other future date should be rejected.

Q. Do you have comments of a general nature to add?

A. While Mohave and Staff have agreed on many of the foundational issues involved in the rate case and have made progress in moving toward consensus on contested issues, the issues that remain unresolved will impact the Cooperative for years to come and should be resolved thoughtfully and prudently. The Mohave Board is democratically elected by cooperative members to represent them when making decisions, including decisions related to rate changes. Each board member lives in the area and will pay the rates they approve and answer to those members that disagree with the decision that is rendered in this case. As I have discussed in my Direct and Rebuttal testimony, the determinations and proposals of these member/customer representatives – the Mohave Board of Directors – should be given great weight by the Commission.

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES

			kWh			Mohave Proposed Rates			Staff Surrebuttal Rates			Mohave Rejoinder Rates		
		Cust	Total	Avg Mn	Adjusted 2010	Proposed 2010	Change $	Change %	Proposed 2010	Change $	Change %	Proposed 2010	Change $	Change %
Residential		34,875	364,970,959	872	42,986,712	44,735,329	1,748,617	4.07%	44,715,743	1,729,031	4.02%	44,775,515	1,788,803	4.16%
Irrigation Time of Use		12	1,730,345	12,016	166,306	168,026	1,720	1.03%	167,368	1,062	0.64%	168,084	1,778	1.07%
Irrigation Pumping		11	2,572,007	19,485	302,194	309,962	7,768	2.57%	308,398	6,204	2.05%	310,144	7,950	2.63%
Subtotal Irrigation		23	4,302,352	15,588	468,500	477,988	9,488	2.03%	475,766	7,266	1.55%	478,228	9,728	2.08%
Small Comm Energy		3,201	42,164,591	1,098	4,900,351	5,177,391	277,040	5.65%	5,224,497	324,146	6.61%	5,183,839	283,488	5.79%
Small Comm Demand		529	70,626,268	11,126	7,389,210	7,729,118	339,908	4.60%	7,720,819	331,609	4.49%	7,736,795	347,585	4.70%
Small Comm TOU		8	1,020,044	10,625	96,177	100,936	4,759	4.95%	101,502	5,325	5.54%	101,047	4,870	5.06%
Subtotal Small Comm		3,738	113,810,903	2,537	12,385,738	13,007,445	621,707	5.02%	13,046,818	661,080	5.34%	13,021,681	635,943	5.13%
Large Comm & Industrial		118	170,994,538	4,495,062	15,775,430	16,108,634	333,204	2.11%	16,160,594	385,164	2.44%	16,115,319	339,889	2.15%
LC&I TOU		3	564,880	15,691	48,035	67,443	19,408	40.40%	61,177	13,142	27.36%	68,657	20,622	42.93%
Lighting Devices	*	1,151	1,100,103	80	98,025	103,184	5,159	5.26%	103,596	5,571	5.68%	104,199	6,174	6.30%
Resale	*	1	46,862,961	3,905,247	3,698,667	3,698,667	0	0.00%	3,698,667	0	0.00%	3,698,667	0	0.00%
Total Energy Sales	*	38,757	702,606,696	1,511	75,461,107	78,198,690	2,737,583	3.63%	78,262,361	2,801,254	3.71%	78,262,266	2,801,159	3.71%
Other Revenue					606,899	863,547	256,647	42.29%	867,282	260,383	42.90%	867,282	260,383	42.90%
Total Revenue					76,068,007	79,062,237	2,994,230	3.94%	79,129,643	3,061,636	4.02%	79,129,548	3,061,541	4.02%

** Total Customers excludes Lighting Devices and Resale*

Data From Supplemental Schedules F-4.0 (Adjusted TY) and N-1.0 (Proposed TY)

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE							
Residential							
Service Charge (12 Month Sum)	417,302	0.00	16.50	16.50	0	6,885,483	6,885,483
Energy Charge per kWh							
First 200 kWh per month	75,441,637	0.081047	0.009029	0.090076	6,114,318	681,163	6,795,481
Next 200 kWh per month	62,783,417	0.081047	0.009029	0.090076	5,088,408	566,871	5,655,279
Next 200 kWh per month	50,237,165	0.094547	0.010529	0.105076	4,749,773	528,947	5,278,720
Next 200 kWh per month	39,197,460	0.094547	0.010529	0.105076	3,706,002	412,710	4,118,712
Next 200 kWh per month	30,436,462	0.094547	0.010529	0.105076	2,877,676	320,466	3,198,142
Over 1,000 kWh per month	106,015,612	0.108047	0.012029	0.120076	11,454,669	1,275,262	12,729,931
Base Revenue	364,111,753				33,990,846	10,670,902	44,661,748
PPCA Revenue					0	0	0
Total Revenue					33,990,846	10,670,902	44,661,748
Residential - Seasonal							
Service Charge (12 Month Sum)	11	0.00	16.50	16.50	0	182	182
Energy Charge per kWh							
First 200 kWh per month	201	0.081047	0.009029	0.090076	16	2	18
Next 200 kWh per month	200	0.081047	0.009029	0.090076	16	2	18
Next 200 kWh per month	148	0.094547	0.010529	0.105076	14	2	16
Next 200 kWh per month	0	0.094547	0.010529	0.105076	0	0	0
Next 200 kWh per month	0	0.094547	0.010529	0.105076	0	0	0
Over 1,000 kWh per month	0	0.108047	0.012029	0.120076	0	0	0
Base Revenue	549				46	188	234
PPCA Revenue					0	0	0
Total Revenue					46	188	234
Residential - Net Metering							
Service Charge (12 Month Sum)	863	0.00	21.50	21.50	0	18,555	18,555
Energy Charge per kWh							
First 200 kWh per month	114,805	0.081047	0.009029	0.090076	9,305	1,037	10,341
Next 200 kWh per month	97,201	0.081047	0.009029	0.090076	7,878	878	8,755
Next 200 kWh per month	79,816	0.094547	0.010529	0.105076	7,546	840	8,387
Next 200 kWh per month	63,706	0.094547	0.010529	0.105076	6,023	671	6,694
Next 200 kWh per month	49,825	0.094547	0.010529	0.105076	4,711	525	5,235
Over 1,000 kWh per month	234,706	0.108047	0.012029	0.120076	25,359	2,823	28,183
Base Revenue	640,060				60,822	25,329	86,150
PPCA Revenue					0	0	0
Total Revenue					60,822	25,329	86,150

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

		Billing	Proposed Rate			Proposed Revenue		
		Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE (Continued)								
Res - Gov								
Service Charge (12 Month Sum)		318	0.00	16.50	16.50	0	5,247	5,247
Energy Charge per kWh								
First	200 kWh per month	60,246	0.081047	0.009029	0.090076	4,883	544	5,427
Next	200 kWh per month	44,692	0.081047	0.009029	0.090076	3,622	404	4,026
Next	200 kWh per month	28,446	0.094547	0.010529	0.105076	2,689	300	2,989
Next	200 kWh per month	20,173	0.094547	0.010529	0.105076	1,907	212	2,120
Next	200 kWh per month	15,693	0.094547	0.010529	0.105076	1,484	165	1,649
Over	1,000 kWh per month	49,347	0.108047	0.012029	0.120076	5,332	594	5,925
Base Revenue		218,597				19,917	7,466	27,383
PPCA Revenue						0	0	0
Total Revenue						19,917	7,466	27,383
Base Revenue		364,970,959				34,071,631	10,703,885	44,775,515
PPCA Revenue						0	0	0
Total Revenue						34,071,631	10,703,885	44,775,515
2. IRRIGATION SERVICE								
Irrigation Time of Use								
Service Charge (12 Month Sum)		144	0.00	66.91	66.91	0	9,635	9,635
On-Peak Demand		2,234.49	8.90	0.00	8.90	19,887	0	19,887
NCP Demand		8,466.81	0.00	1.62	1.62	0	13,716	13,716
Energy Charge per kWh		1,730,345	0.072135	0.000016	0.072151	124,818	28	124,846
Base Revenue						144,705	23,379	168,084
PPCA Revenue						0	0	0
Total Revenue						144,705	23,379	168,084
Irrigation Pumping								
Service Charge (12 Month Sum)		132	0.00	61.76	61.76	0	8,152	8,152
NCP Demand		12,025.74	5.90	1.62	7.52	70,952	19,482	90,434
Energy Charge per kWh		2,572,007	0.072135	0.010119	0.082254	185,532	26,026	211,558
Base Revenue						256,484	53,660	310,144
PPCA Revenue						0	0	0
Total Revenue						256,484	53,660	310,144
Base Revenue		4,302,352				401,189	77,039	478,228
PPCA Revenue						0	0	0
Total Revenue						401,189	77,039	478,228

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE							
Sm Comm Demand - Net Metering							
Service Charge (12 Month Sum)	5	0.00	36.03	36.03	0	180	180
NCP Demand > 3 kW	73.68	6.31	4.69	11.00	465	346	810
Energy Charge per kWh	24,280	0.073000	0.000038	0.073038	1,772	1	1,773
Base Revenue					2,237	527	2,763
PPCA Revenue					0	0	0
Total Revenue					2,237	527	2,763
Small Commercial Demand							
Service Charge (12 Month Sum)	5,552	0.00	36.03	36.03	0	200,039	200,039
NCP Demand > 3 kW	187,060.45	6.31	4.69	11.00	1,180,351	877,314	2,057,665
Energy Charge per kWh	63,019,478	0.073000	0.000038	0.073038	4,600,422	2,395	4,602,817
Base Revenue					5,780,773	1,079,748	6,860,521
PPCA Revenue					0	0	0
Total Revenue					5,780,773	1,079,748	6,860,521
Small Commercial Energy							
Service Charge (12 Month Sum)	35,164	0.00	21.50	21.50	0	756,026	756,026
Energy Charge per kWh	38,541,431	0.088094	0.015252	0.103346	3,395,269	587,834	3,983,103
Base Revenue					3,395,269	1,343,860	4,739,129
PPCA Revenue					0	0	0
Total Revenue					3,395,269	1,343,860	4,739,129
Small Commercial - Net Metering							
Service Charge (12 Month Sum)	49	0.00	26.50	26.50	0	1,299	1,299
Energy Charge per kWh	64,010	0.088094	0.015252	0.103346	5,639	976	6,615
Base Revenue					5,639	2,275	7,914
PPCA Revenue					0	0	0
Total Revenue					5,639	2,275	7,914
Small Commercial TOU							
Service Charge (12 Month Sum)	91	0.00	41.03	41.03	0	3,734	3,734
On-Peak Demand	1,430.12	15.00	0.00	15.00	21,452	0	21,452
NCP kW	3,175.62	0.00	4.69	4.69	0	14,894	14,894
Energy Charge per kWh	1,020,044	0.045185	0.014584	0.059769	46,091	14,876	60,967
Base Revenue					67,543	33,504	101,047
PPCA Revenue					0	0	0
Total Revenue					67,543	33,504	101,047
SC Energy Gov							
Service Charge (12 Month Sum)	3,208	0.00	21.50	21.50	0	68,972	68,972
Energy Charge per kWh	3,559,150	0.088094	0.015252	0.103346	313,540	54,284	367,824
Base Revenue					313,540	123,256	436,796
PPCA Revenue					0	0	0
Total Revenue					313,540	123,256	436,796

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE (Continued)							
SC Demand Gov							
Service Charge (12 Month Sum)	784	0.00	36.03	36.03	0	28,248	28,248
NCP Demand > 3 kW	26,495.68	6.31	4.69	11.00	167,188	124,265	291,452
Energy Charge per kWh	7,582,510	0.073000	0.000038	0.073038	553,523	288	553,811
Base Revenue					720,711	152,801	873,511
PPCA Revenue					0	0	0
Total Revenue					720,711	152,801	873,511
Base Revenue	113,810,903				10,285,712	2,735,971	13,021,681
PPCA Revenue					0	0	0
Total Revenue					10,285,712	2,735,971	13,021,681
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE							
Large C&I Secondary							
Service Charge (12 Month Sum)	983	0.00	175.00	175.00	0	172,025	172,025
NCP Demand	189,369.16	7.76	3.22	10.98	1,469,505	609,769	2,079,273
Energy Charge per kWh	76,311,058	0.064184	0.005709	0.069893	4,897,949	435,660	5,333,609
Base Revenue					6,367,454	1,217,454	7,584,907
PPCA Revenue					0	0	0
Total Revenue					6,367,454	1,217,454	7,584,907
Large C&I Primary							
Service Charge (12 Month Sum)	36	0.00	175.00	175.00	0	6,300	6,300
NCP Demand	17,172.00	7.76	3.22	10.98	133,255	55,294	188,549
Energy Charge per kWh	8,497,320	0.064184	0.005709	0.069893	545,392	48,511	593,903
Primary Discount on Demand & Energy		-1.00%	-1.00%	-1.00%	(6,786)	(1,038)	(7,825)
Base Revenue					671,861	109,067	780,927
PPCA Revenue					0	0	0
Total Revenue					671,861	109,067	780,927

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
Large C&I TOU							
Service Charge (12 Month Sum)	31	0.00	180.00	180.00	0	5,580	5,580
On-Peak Demand	690.80	23.00	0.00	23.00	15,888	0	15,888
NCP kW	5,713.20	0.00	3.22	3.22	0	18,397	18,397
Energy Charge per kWh	564,880	0.045261	0.005709	0.050970	25,567	3,225	28,792
Base Revenue					41,455	27,202	68,657
PPCA Revenue					0	0	0
Total Revenue					41,455	27,202	68,657
Large C&I GOV							
Service Charge (12 Month Sum)	362	0.00	175.00	175.00	0	63,350	63,350
NCP Demand	64,343.36	7.76	3.22	10.98	499,304	207,186	706,490
Energy Charge per kWh	17,180,160	0.064184	0.005709	0.069893	1,102,691	98,082	1,200,773
Base Revenue					1,601,995	368,618	1,970,613
PPCA Revenue					0	0	0
Total Revenue					1,601,995	368,618	1,970,613
LC&I Trans (Current TOU) — *Billed at Subtransmission Delivery Level*							
Service Charge (12 Month Sum)	12	0.00	175.00	175.00	0	2,100	2,100
NCP kW	53,106.00	7.76	3.22	10.98	412,103	171,001	583,104
Energy Charge per kWh	30,204,000	0.064184	0.005709	0.069893	1,938,614	172,435	2,111,048
Subtransmission Discount on Demand & Energy		-7.50%	-7.50%	-7.50%	(176,304)	(25,758)	(202,061)
Base Revenue					2,174,413	319,778	2,494,191
PPCA Revenue					0	0	0
Total Revenue					2,174,413	319,778	2,494,191

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

		Billing	Proposed Rate			Proposed Revenue		
		Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)								
LP Substation	***Billed at Substation Delivery Level***							
Service Charge (12 Month Sum)		24	0.00	175.00	175.00	0	4,200	4,200
NCP kW		67,500.00	7.76	3.22	10.98	523,800	217,350	741,150
Energy Charge per kWh		38,802,000	0.064184	0.005709	0.069893	2,490,468	221,521	2,711,988
Substation Discount on Demand & Energy			-5.00%	-5.00%	-5.00%	(150,713)	(21,944)	(172,657)
Base Revenue						2,863,555	421,127	3,284,681
PPCA Revenue						0	0	0
Total Revenue						2,863,555	421,127	3,284,681
Base Revenue		171,559,418				13,720,733	2,463,246	16,183,976
PPCA Revenue						0	0	0
Total Revenue						13,720,733	2,463,246	16,183,976
5. LIGHTING SERVICE								
175 W MVL	102 kWh per month	6,039	6.19	0.98	7.17	37,381	5,918	43,300
100 W HPS	51 kWh per month	2,594	3.09	5.39	8.48	8,015	13,982	21,997
175 W MVL CO	101 kWh per month	320	6.13	0.51	6.64	1,962	163	2,125
100 W HPS CO	51 kWh per month	3,644	3.09	2.34	5.43	11,260	8,527	19,787
250 W HPS	130 kWh per month	1,211	7.89	6.14	14.03	9,555	7,436	16,990
Base Revenue		13,808				68,173	36,026	104,199
PPCA Revenue						0	0	0
Total Revenue						68,173	36,026	104,199
kWh		1,100,103						
6. RESALE REVENUE								
Base Revenue						3,222,980	475,687	3,698,667
PPCA Revenue						0	0	0
Total Revenue		46,862,961				3,222,980	475,687	3,698,667

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
7. TOTAL REVENUE							
Base Revenue	702,606,696				61,770,418	16,491,854	78,262,266
PPCA Revenue					0	0	0
Other Revenue					0	863,547	863,547
Total					61,770,418	17,355,401	79,125,813

PPCA Revenue Developed on Sup Schedule N-2.1
Customers - Sup Schedule F-1.1
kWh Usage - Sup Schedule F-2.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL TIME OF USE RATES - 2010 DATA

			Billing	Proposed Rate			Proposed Revenue		
			Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE									
Proposed Residential Rate									
Service Charge (12 Month Sum)			417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First	400	kWh per month	138,330,393	0.081047	0.009029	0.090076	11,211,263	1,248,985	12,460,248
Next	600	kWh per month	119,935,547	0.094547	0.010529	0.105076	11,339,546	1,262,801	12,602,348
Over	1,000	kWh per month	106,705,019	0.108047	0.012029	0.120076	11,529,157	1,283,555	12,812,712
Total									
Base Revenue			364,970,959				34,079,966	10,686,253	44,766,220
PPCA Revenue							0	0	0
Total Revenue							34,079,966	10,686,253	44,766,220

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL TIME OF USE RATES - 2010 DATA

			Billing Units	Proposed Rate Pur Pwr	Proposed Rate Dist Wires	Proposed Rate Total	Proposed Revenue Pur Pwr	Proposed Revenue Dist Wires	Proposed Revenue Total
Proposed Residential Time of Use - Including Weekends On-peak									
Service Charge (12 Month Sum)			417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Desired Discount	**2.5%**	**Applied to Power Supply**							
Calculated Discount on total Energy Charges				**2.26%**					
Estimated On Peak kWh									
First	400	kWh per month	33,199,294	0.190142	0.009029	0.199171	6,312,580	299,756	6,612,337
Next	600	kWh per month	28,784,531	0.203304	0.010529	0.213833	5,852,010	303,072	6,155,083
Over	1,000	kWh per month	25,609,205	0.216467	0.012029	0.228496	5,543,548	308,053	5,851,601
Total			87,593,030						
Estimated Off Peak kWh									
First	400	kWh per month	105,131,099	0.046904	0.009029	0.055933	4,931,069	949,229	5,880,298
Next	600	kWh per month	91,151,016	0.060067	0.010529	0.070596	5,475,168	959,729	6,434,897
Over	1,000	kWh per month	81,095,814	0.073229	0.012029	0.085258	5,938,565	975,502	6,914,067
Total			277,377,929						
Base Revenue			364,970,959				34,052,940	12,774,408	46,827,350
PPCA Revenue							0	0	0
Total Revenue							34,052,940	12,774,408	46,827,350
Proposed Residential Time of Use - Excluding Weekends On-Peak									
Service Charge (12 Month Sum)			417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Assumed Off Peak kWh %	**76%**								
Estimated On Peak kWh									
First	400	kWh per month	33,199,294	0.195017	0.009029	0.204046	6,474,427	299,756	6,774,183
Next	600	kWh per month	28,784,531	0.208517	0.010529	0.219046	6,002,064	303,072	6,305,136
Over	1,000	kWh per month	25,609,205	0.222017	0.012029	0.234046	5,685,679	308,053	5,993,732
Total			87,593,030						
Estimated Off Peak kWh									
First	400	kWh per month	105,131,099	0.048107	0.009029	0.057136	5,057,542	949,229	6,006,770
Next	600	kWh per month	91,151,016	0.061607	0.010529	0.072136	5,615,541	959,729	6,575,270
Over	1,000	kWh per month	81,095,814	0.075107	0.012029	0.087136	6,090,863	975,502	7,066,365
Total			277,377,929						
Base Revenue			364,970,959				34,926,116	12,774,408	47,700,523
PPCA Revenue							0	0	0
Total Revenue							34,926,116	12,774,408	47,700,523

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF RESIDENTIAL DEMAND RATES - 2010 DATA

				Billing	Proposed Rate			Proposed Revenue		
				Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
1. RESIDENTIAL SERVICE										
Proposed Residential Rate										
Service Charge (12 Month Sum)				417,631	0.00	16.50	16.50	0	6,890,912	6,890,912
First	400	kWh per month		138,330,393	0.081047	0.009029	0.090076	11,211,263	1,248,985	12,460,248
Next	600	kWh per month		119,935,547	0.094547	0.010529	0.105076	11,339,546	1,262,801	12,602,348
Over	1,000	kWh per month		106,705,019	0.108047	0.012029	0.120076	11,529,157	1,283,555	12,812,712
Total										
Base Revenue				364,970,959				34,079,966	10,686,253	44,766,220
PPCA Revenue								0	0	0
Total Revenue								34,079,966	10,686,253	44,766,220

				Billing	Proposed Rate			Proposed Revenue		
				Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
Proposed Residential Demand Rate										
Service Charge (12 Month Sum)				417,631	0.00	21.50	21.50	0	8,979,067	8,979,067
Demand Charge		Assumed	3.00	1,252,893	8.00	0.50	8.50	10,023,144	626,447	10,649,591
First	400	kWh per month		138,330,393	0.053584	0.007370	0.060954	7,412,296	1,019,495	8,431,791
Next	600	kWh per month		119,935,547	0.067084	0.008870	0.075954	8,045,756	1,063,828	9,109,585
Over	1,000	kWh per month		106,705,019	0.080584	0.010370	0.090954	8,598,717	1,106,531	9,705,248
Total				364,970,959						
Base Revenue								34,079,913	12,795,368	46,875,282
PPCA Revenue								0	0	0
Total Revenue								34,079,913	12,795,368	46,875,282

Q:\Projects\Analytical\COS\AZ\MOHAVE\2010Retail Rates\Rejoinder\MWS Rejoinder data.xls MWS Rejoinder data.xls Income 3/23/2012 11:31 AM

MOHAVE ELECTRIC COOPERATIVE, INC.

STAFF'S SURREBUTTAL ADJUSTED INCOME STATEMENT
SUPPLEMENTAL DATA FOR THE YEAR ENDING DECEMBER 31, 2010

	Mohave Adjusted 12/31/2010 (a)	Staff Adjustments CSB-3 (b)	Staff Adjusted Test Year (c)	Staff Recommended Change (d)	Staff Recommended (e)	Mohave Rejoinder 12/31/2010 (a)	Mohave Rejoinder Adjustments (b)	Mohave Rejoinder Adj TY (c)	Mohave Rejoinder Recommended Change (d)	Mohave Rejoinder Recommended (e)
Operating Revenues										
1 Base Revenue (Remainder)	$ 56,732,893	$ 15,505,234	$ 72,238,127	$ 2,801,146	$ 75,039,273	$ 56,732,893	$ 15,505,234	$ 72,238,127	$ 2,801,146	$ 75,039,273
2 Base Revenue (TPS Pur Pwr)	3,222,980		3,222,980		3,222,980	3,222,980		3,222,980		3,222,980
3 PCA	15,505,234	(15,505,234)	0		0	15,505,234	(15,505,234)	0		0
4 Other	606,899		606,899	260,383	867,282	606,899		606,899	260,383	867,282
5 Total	$ 76,068,006	$ 0	$ 76,068,006	$ 3,061,529	$ 79,129,535	$ 76,068,006	$ 0	$ 76,068,006	$ 3,061,529	$ 79,129,535
6										
7 **Operating Expenses**										
8 Purchased Power	$ 61,802,677	$ (594,737)	$ 61,207,940	$	$ 61,207,940	$ 61,802,677	$ (32,702)	$ 61,769,975	$	$ 61,769,975
9 SubTransmission O&M	169,400		169,400		169,400	169,400		169,400		169,400
10 Distribution-Operations	2,773,698		2,773,698		2,773,698	2,773,698		2,773,698		2,773,698
11 Distribution-Maintenance	1,194,657		1,194,657		1,194,657	1,194,657		1,194,657		1,194,657
12 Consumer Accounting	2,227,246		2,227,246		2,227,246	2,227,246		2,227,246		2,227,246
13 Customer Service	196,226		196,226		196,226	196,226		196,226		196,226
14 Sales	96,252		96,252		96,252	96,252		96,252		96,252
15 Administrative & General	4,756,463	662,035	5,418,498		5,418,498	4,756,463	100,000	4,856,463		4,856,463
16 Depreciation	2,239,666		2,239,666		2,239,666	2,239,666		2,239,666		2,239,666
17 Tax	0		0		0	0		0		0
18 Total	$ 75,456,285	$ 67,298	$ 75,523,583	$ 0	$ 75,523,583	$ 75,456,285	$ 67,298	$ 75,523,583	$ 0	$ 75,523,583
19										
20 Return	$ 611,721	$ (67,298)	$ 544,423	$ 3,061,529	$ 3,605,952	$ 611,721	$ (67,298)	$ 544,423	$ 3,061,529	$ 3,605,952
21										
22 **Interest & Other Deductions**										
23 Interest L-T Debt	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308
24 Amortize RUS Gain	0		0		0	0		0		0
25 Interest-Other	142,396		142,396		142,396	142,396		142,396		142,396
26 Other Deductions	17,024		17,024		17,024	17,024		17,024		17,024
27 Total	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728
28										
29 Operating Margin	$ (1,709,007)	$ (67,298)	$ (1,776,305)	$ 3,061,529	$ 1,285,224	$ (1,709,007)	$ (67,298)	$ (1,776,305)	$ 3,061,529	$ 1,285,224
30										
31 **Non-Operating Margins**										
32 Interest Income	$ 410,049	$	$ 410,049	$	$ 410,049	$ 410,049	$	$ 410,049	$	$ 410,049
33 Gain(Loss) Equity Investments	110,369		110,369		110,369	110,369		110,369		110,369
34 Other Margins	(32,307)		(32,307)		(32,307)	(32,307)		(32,307)		(32,307)
35 G&T Capital Credits	3,509,969		3,509,969		3,509,969	3,509,969		3,509,969		3,509,969
36 Other Capital Credits	107,687		107,687		107,687	107,687		107,687		107,687
37 Total	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767
38										
39 Net Margins	$ 2,396,760	$ (67,298)	$ 2,329,462	$ 3,061,529	$ 5,390,991	$ 2,396,760	$ (67,298)	$ 2,329,462	$ 3,061,529	$ 5,390,991
40 Rate Change					4.025%					4.025%
41 Operating TIER					1.59					1.59

Mohave Rejoinder Schedule MWS-5

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED PPCA BASE COST - 2010 DATA

	Mohave Original Filing			Staff Recommendation			Mohave Rebuttal		
	Adjusted 2010	Proposed 2010	Difference	Adjusted 2010	Proposed 2010	Difference	Adjusted 2010	Proposed 2010	Difference
Total kWh Sales	655,743,735	655,743,735	0	655,743,735	655,743,735	0	655,743,735	655,743,735	0
Less Lighting kWh Sales	1,100,103		(1,100,103)	1,100,103		(1,100,103)	1,100,103		(1,100,103)
Jurisdictional kWh Sales	654,643,632	655,743,735	1,100,103	654,643,632	655,743,735	1,100,103	654,643,632	655,743,735	1,100,103
Jurisdictional Purchased Power	58,579,697	58,579,697	0	58,579,697	58,579,697	0	58,579,697	58,579,697	0
Remove Consultants & Attorney			0		-571,723	(571,723)		-32,702	(32,702)
Remove Fuel Bank Consulting					-23,015				
Remove TPS Margins (PP already removed)					-475,687				
Purchased Power	58,579,697	58,579,697	0	58,579,697	57,509,272	(1,070,424)	58,579,697	58,546,995	(32,702)
Power Cost per kWh Sold	0.089483	0.089333	(0.000150)	0.089483	0.087701	(0.001782)	0.089483	0.089283	(0.000200)
Authorized Base Cost	0.065798	**0.091183**	0.025385	0.065798	**0.087701**	0.021903	0.065798	**0.089283**	0.023485
Average PPCA Factor	0.023685	(0.001850)	(0.025535)	0.023685	0.000000	(0.023685)	0.023685	0.000000	(0.023685)

Adjusted 2010 Power Cost on Supplemental Schedule F-7.0
Adjusted 2010 kWh Sales on Supplemental Schedule F-2.0
Note: PPCA to be charged on lighting under new rates

MOHAVE ELECTRIC COOPERATIVE, INC.

SUMMARY OF RATES

	Existing Rate	Staff Surrebuttal	Mohave Rejoinder
Power Cost, per kWh Sold	$0.089483	$0.087701	$0.089283
PPCA Base Cost, per kWh Sold	$0.065798	$0.087701	$0.089283
PPCA Factor, per kWh	$0.023685	$0.000000	$0.000000
Residential Service			
Service Charge, per month	$9.50	$13.50	$16.50
First 400 kWh per month	$0.083190	$0.093351	$0.090076
Next 600 kWh per month	$0.083190	$0.108351	$0.105076
Over 1,000 kWh per month	$0.083190	$0.123351	$0.120076
Optional Res Time of Use - Excludes Weekends			
Service Charge, per month	$15.00	$18.50	$21.50
On-Peak Energy Charge, per kWh			
First 400 kWh per month	$0.149500		$0.204046
Next 600 kWh per month	$0.149500		$0.219046
Over 1,000 kWh per month	$0.149500		$0.234046
Off-Peak Energy Charge, per kWh			
First 400 kWh per month	$0.052000		$0.057136
Next 600 kWh per month	$0.052000		$0.072136
Over 1,000 kWh per month	$0.052000		$0.087136
Optional Res Time of Use - Includes Weekends			
Discount on all energy charges excluding PPCA		2.25%	2.25%
Experimental Residential Demand Service			
Service Charge, per month	$13.50	$18.50	$21.50
Demand Charge, per NCP kW	$7.50		$8.50
First 400 kWh per month	$0.048000		$0.060954
Next 600 kWh per month	$0.048000		$0.075954
Over 1,000 kWh per month	$0.048000		$0.090954

MOHAVE ELECTRIC COOPERATIVE, INC.
SUMMARY OF RATES

	Existing Rate	Staff Surrebuttal	Mohave Rejoinder
Power Cost, per kWh Sold	$0.089483	$0.087701	$0.089283
PPCA Base Cost, per kWh Sold	$0.065798	$0.087701	$0.089283
PPCA Factor, per kWh	$0.023685	$0.000000	$0.000000
Irrigation			
Service Charge, per month	$60.00	$61.76	$61.76
Demand Charge, per NCP kW	$7.00	$7.42	$7.52
Energy Charge, per kWh	$0.058000	$0.082043	$0.082254
Irrigation Time of Use			
Service Charge, per month	$60.00	$66.91	$66.91
On Peak Demand Charge, per on peak kW	$13.50	$8.63	$8.90
Demand Charge, per NCP kW	$0.00	$1.68	$1.62
Energy Charge, per kWh	$0.050000	$0.071792	$0.072151
Small Commercial - Energy			
Service Charge, per month	$12.00	$18.50	$21.50
Energy Charge, per kWh	$0.081600	$0.107048	$0.103346
Small Commercial - Demand			
Service Charge, per month	$25.00	$36.03	$36.03
Billing Demand Charge, per NCP kW > 3 kW	$8.25	$10.82	$11.00
All kWh per month	$0.053740	$0.073351	$0.073038
Small Commercial - Time of Use			
Service Charge, per month	$30.00	$41.01	$41.03
On Peak Demand Charge, per on peak kW	$12.50	$14.45	$15.00
Demand Charge, per NCP kW		$4.69	$4.69
All kWh per month	$0.050400	$0.060989	$0.059769

MOHAVE ELECTRIC COOPERATIVE, INC.

SUMMARY OF RATES

	Existing Rate	Staff Surrebuttal	Mohave Rejoinder
Power Cost, per kWh Sold	$0.089483	$0.087701	$0.089283
PPCA Base Cost, per kWh Sold	$0.065798	$0.087701	$0.089283
PPCA Factor, per kWh	$0.023685	$0.000000	$0.000000
Large Commercial & Industrial			
Customer Charge, per month	$70.00	$175.00	$175.00
Demand Charge, per NCP kW	$9.75	$11.03	$10.98
Energy Charge, per kWh	$0.045580	$0.070052	$0.069893
Large Commercial & Ind Time of Use- New Customers			
Customer Charge, per month	$70.00	$189.00	$180.00
On Peak Demand Charge, per on peak kW	$13.50	$11.11	$23.00
Demand Charge, per NCP kW		$3.22	$3.22
Energy Charge, per kWh	$0.041000	$0.051775	$0.050970
Large Commercial & Ind Time of Use - Existing Customers			
Customer Charge, per month	$70.00	$189.00	$180.00
On Peak Demand Charge, per on peak kW	$13.50	$23.00	$23.00
Demand Charge, per NCP kW		$3.22	$3.22
Energy Charge, per kWh	$0.041000	$0.051755	$0.050970
Discount on Dem & Ener - Subtransmission Service	0.00%	-7.50%	-7.50%
Discount on Dem & Ener - Substation Service	0.00%	-5.00%	-5.00%
Discount on Dem & Ener - Dist Primary Service	0.00%	-1.00%	-1.00%

MOHAVE ELECTRIC COOPERATIVE, INC.

SUMMARY OF RATES

			Existing Rate	Staff Surrebuttal	Mohave Rejoinder
Power Cost, per kWh Sold			$0.089483	$0.087701	$0.089283
PPCA Base Cost, per kWh Sold			$0.065798	$0.087701	$0.089283
PPCA Factor, per kWh			$0.023685	$0.000000	$0.000000
Lighting					
175 W MVL	100	kWh per month	$6.85	$7.11	$7.17
100 W HPS	50	kWh per month	$7.88	$8.46	$8.48
175 W MVL CO	100	kWh per month	$5.11	$6.58	$6.64
100 W HPS CO	50	kWh per month	$5.11	$5.41	$5.43
250 W HPS	129	kWh per month	$13.18	$13.95	$14.03
			No PCA	*PCA*	*PCA*

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - 2010 USAGE
RESIDENTIAL SERVICE

kWh Usage	Monthly * Cust	Existing Rate	Staff Surrebuttal	Mohave Rejoinder	Change - $ Staff	Change - $ Rejoinder	Change - % Staff	Change - % Rejoinder
Service Charge		$9.50	$13.50	**$16.50**	$4.00	**$7.00**	42.11%	**73.68%**
Energy Charge, per kWh								
First 400		$0.083190	$0.093351	**$0.090076**	$0.010161	**$0.006886**	12.21%	**8.28%**
Next 600		$0.083190	$0.108351	**$0.105076**	$0.025161	**$0.021886**	30.25%	**26.31%**
Over 1,000		$0.083190	$0.123351	**$0.120076**	$0.040161	**$0.036886**	48.28%	**44.34%**
PPCA Factor		$0.023685	$0.000000	**$0.000000**	($0.023685)	**($0.023685)**	-100.00%	**-100.00%**
Total Energy Charge plus PPCA								
First 400		$0.106875	$0.093351	**$0.090076**	($0.013524)	**($0.016799)**	-12.65%	**-15.72%**
Next 600		$0.106875	$0.108351	**$0.105076**	$0.001476	**($0.001799)**	1.38%	**-1.68%**
Over 1,000		$0.106875	$0.123351	**$0.120076**	$0.016476	**$0.013201**	15.42%	**12.35%**
0	1,009	$9.50	$13.50	**$16.50**	$4.00	**$7.00**	42.11%	**73.68%**
100	2,913	$20.19	$22.84	**$25.51**	$2.65	**$5.32**	13.12%	**26.35%**
200	2,687	$30.88	$32.17	**$34.52**	$1.30	**$3.64**	4.19%	**11.79%**
400	5,213	$52.25	$50.84	**$52.53**	($1.41)	**$0.28**	-2.70%	**0.54%**
800	9,166	$95.00	$94.18	**$94.56**	($0.82)	**($0.44)**	-0.86%	**-0.46%**
1,000	3,212	$116.38	$115.85	**$115.58**	($0.52)	**($0.80)**	-0.45%	**-0.69%**
2,000	7,881	$223.25	$239.20	**$235.65**	$15.95	**$12.40**	7.15%	**5.56%**
3,000	2,466	$330.13	$362.55	**$355.73**	$32.43	**$25.60**	9.82%	**7.76%**
5,000	738	$543.88	$609.26	**$595.88**	$65.38	**$52.01**	12.02%	**9.56%**
8,000	54	$864.50	$979.31	**$956.11**	$114.81	**$91.61**	13.28%	**10.60%**
Over	4							
860 Average		**$101.41**	**$100.68**	**$100.87**	**($0.73)**	**($0.55)**	**-0.72%**	**-0.54%**
637 Median		**$77.58**	**$76.52**	**$77.43**	**($1.06)**	**($0.15)**	**-1.37%**	**-0.19%**

** Customers with usage from the previous block to this block*

Mohave Electric Cooperative, Inc. E-01750A-11-0136

October 3, 2011

ORIGINAL

Corporation Commissioners,

My name is Greg Raymond and I live in the Mohave Electric Cooperative service area. Even though I do not like it, I understand the Cooperatives current rate increase proposal and the reasons for it. There are a couple issues that I would like to address, one of which is directly related to this issue.

I do not agree with placing fixed costs into the energy rate. I believe that fixed costs need to be de-coupled and added to all Coop members equally because that would be fairer, hence the coop concept. It appears that the majority of Mohave Electric Coop's shortfall right now is in its operations budget, which is directly related to the fixed costs. Please make these costs, collected under the Customer Charge, be equal to all members/users. The electricity is there for all to use and connect to, please don't place the burden of these costs on a use based system, the more you use the more you pay, for these operational costs. these costs should be shared equaly amongst all users.

My other concern is that about the negative publicity that is going around about smart meters. Do people not realize that similar technology meters have been attached to their gas meters years ago and most people are already connected to utilities via phone line or cable and/or internet? Why all of a sudden a big problem with another utility moving forward in technology? The electrical system of this country needs to modernize and get into the tech game, smart meters do this. I can now watch my daily usage and adjust if need be because of smart meter technology. Please do not allow a few paranoid people disrupt the deployment of this wonderful technology.

Allowing people to 'opt out' of this progressing system would only sustain current operations, which due to the increases in costs, would increase costs overall. Those costs would have to be absorbed, not just by them but by all members, which again would not be fair. Please research this issue more to see the true reality before allowing people to be steered to an uneducated and more expensive way of doing business.

Thank you for your considerations in these matters.Should you like to discuss this further please feel free to call me [redacted]

Sincerely,

Greg Raymond

Arizona Corporation Commission
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AZ CORP COMMISSION
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Mohave Rejoinder Exhibit MWS-9

ORIGINAL

E-01750A-11-0136

Jennifer Ybarra

From: Joe Anderson [asstchief@bullheadfire.org]
Sent: Friday, September 23, 2011 8:35 AM
To: Newman-Web
Subject: Electric rate increases

September 23, 2011

Corporation Commissioners Newman,

My name is Joe Anderson and I live in the Mohave Electric Cooperative service area and have been for the past 34 years. Even though I do not like it, I understand the Cooperatives current rate increase proposal and the reasons for it. There are a couple issues that I would like to address, one of which is directly related to this issue.

I do not agree with placing fixed costs into the energy rate. I believe that fixed costs need to be de-coupled and added to all Coop members equally because that would be fairer. It appears that the majority of Mohave Electric Coop's shortfall right now is in its operations budget, which is directly related to the fixed costs. Please make these costs, collected under the Customer Charge, be equal to all members/users.

My other concern is that about the negative publicity that is going around about smart meters. Do people not realize that similar technology meters have been attached to their gas meters years ago and most people are already connected to utilities via phone line or cable and/or internet? Why all of a sudden a big problem with another utility moving forward in technology?

Allowing people to 'opt out' of this progressing system would only sustain current operations, which due to the increases in costs, would increase costs overall. Those costs would have to be absorbed, not just by them but by all members, which again would not be fair. Please research this issue more to see the true reality before allowing people to be steered to an uneducated and more expensive way of doing business.

Thank you for your considerations in these matters.

Arizona Corporation Commission
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OCT 24 2011
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Sincerely,
Joe Anderson

AZ CORP COMMISSION
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Mohave Rejoinder Exhibit MWS-9

ORIGINAL

lectric Cooperative, Inc., E-01750A-11-0136 Dec 7 2011

Arizona Corporation Commission
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To All members of the Arizona Corp Comm.
1200 West Washington

I am a full time resident of Bullhead City and am served by Mohave Electric Coop. for all my electrical needs.

I have read that we are about to face a rate increase. I would like to add my support to the one part of the proposed rate increase. I totaly support the idea of separating or de-coupling the fixed costs and the energy costs. These fixed costs should be collected entirely in the customer charge.

My part time neighbor pays a smaller percentage of fixed cost for upkeep and maintance of the system.

We should all pay the same fixed charge seperate from our energy costs,

Thank you Michael Bartlett

Mohave Rejoinder Exhibit MWS-9

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01750A-11-0136

EXHIBIT
MEC-5

REBUTTAL TESTIMONY OF

CARL N. STOVER, JR., P.E.

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

February 23, 2012

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF

CARL N. STOVER, JR., P.E.

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

SUMMARY OF REBUTTAL TESTIMONY

Mr. Stover provides rebuttal testimony related to Staff's recommendations that would result in Mohave writing-off approximately $3.1 million[1] consisting of prudence costs and power supply-related costs. The staff recommended disallowance is greater than the approximate $2.9 million rate increase proposed by the Staff.

With regard to the prudence cost, Mr. Stover will show that Staff's rationale for $1.946 million of the proposed write-off which is based on sending "... a signal that a utility can avoid scrutiny by failing to maintain records and file requested information." (reference Mendl testimony page 27, line 27) is inapplicable to Mohave because Mohave has provided all required data supporting purchased power costs applicable for the PPCA bank and timely objected to resubmitting data provided to Staff in the past.

With regard to the power supply related costs which Mr. Mendl characterizes as ineligible cost, Mr. Stover will show that the Staff specifically allows the costs at issue to be recovered and the only question is how the costs are recovered and whether the PPCA bank balance is to be adjusted.

Mr. Stover will also explain why Mohave's current method of dealing with third-party sales is appropriate, consistent with past practices, and in the best interest of the retail member-consumers.

Finally Mr. Stover will show that the Staff recommendation will have a serious negative impact on Mohave's financials and is not in the best interest of the retail member consumers that own Mohave.

[1] Components include:

2001-2006 prudence cost	$1.946 million
Test Year power supply cost:	$562,035
Estimated 2011- current:	$562.035

Mr. Stover recommends:

1. Prudence adjustment related to 2008 power cost be rejected (Staff has already agreed with this recommendation)
2. Prudence adjustment (sanction) related to Mohave's timely objection to producing 7/25/2001 – 12/31/2006 data be rejected.
3. Power supply related cost:
    a. Lobbying cost be removed from recoverable cost.
    b. All other disputed costs continue to be part of PPCA. Alternatively, continue recovery under the PPCA until revised rates with test year costs included in base rates are effective.
4. Third-party sales:
    a. Continue current treatment, as consistent with Commission treatment of other sales excluded from PPCA and discussions with Staff in 2004 and also providing the greatest equity to the member consumers.
    b. If treatment is changed, then make appropriate adjustment to base purchased power cost as described by Mr. Searcy.

1. INTRODUCTION

Q. PLEASE STATE YOUR NAME, YOUR EMPLOYER AND YOUR POSITION.

A. My name is Carl N. Stover, Jr., and I am employed by C. H. Guernsey & Company.

Q. ARE YOU THE SAME CARL N. STOVER, JR. WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously presented Direct and Supplemental Testimony in this matter on behalf of Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative") in this proceeding.

2. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony focuses on the following:

1. Staff witness Mendl's recommendation that the Mohave purchased power cost adjuster (PPCA) bank balance be reduced by $163,222 for undocumented 2008 transmission costs.

2. Staff witness Mendl's recommendation that the Mohave PPCA bank balance be reduced by $1.946 million as a sanction for Mohave timely objecting to producing detailed support for power costs prior to 2007.

3. Staff witness Mendl's recommendation that the Mohave PPCA bank balance be reduced by $594,737 related to power purchase related costs, $562,035 of which Staff allowed as re-categorized administrative and general expenses and $32,702 of which Staff disallowed as lobbying expenses.

4. Staff witness Mendl's recommendations related to the treatment of third-party sales.

5. Staff witness Mendl's recommendation that Mohave reconsider the limit on power purchased from the spot market.

Q. DID YOU PREPARE EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes.

Q. WERE THE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. DO YOU HAVE ANY GENERAL COMMENTS ON MR. MENDL'S PRUDENCE REVIEW AND TESTIMONY?

A. In reviewing Mr. Mendl's direct testimony, while not agreeing with all of his conclusions and recommendations, I found the general approach taken to evaluate Mohave's procurement process sound. However, it is insufficiently tailored to an electric distribution cooperative that is owned and governed by its member-customers, making a transition to a partial requirements member of a G&T cooperative, still making the vast majority of its power purchases under contracts and rates approved by the Arizona Corporation Commission and submitting monthly fuel bank reports to Commission Staff for the specific purposes of tracking and monitoring the Cooperative's purchase power bank balance and ensuring the costs of purchased power are accurately calculated and documented. As a result, Mr. Mendl's recommendations to penalize Mohave in the absence of any evidence of wrongdoing are inappropriate and should be rejected.

3. MR. MENDL'S RECOMMENDATION TO REDUCE THE PURCHASED POWER BANK BALANCE BY $163,222 FOR UNDOCUMENTED 2008 POWER COST IS NO LONGER AT ISSUE

Q. WHAT IS THE NATURE OF THIS ADJUSTMENT?

A. Mr. Mendl stated he made an adjustment of $163,221.69 related to firm transmission services provided by the Western Area Power Administration ("WAPA" or "Western") for the months of June through November 2008.

Q. DID HE MAKE THE ADJUSTMENT BECAUSE THERE WAS A QUESTION AS TO WHETHER OR NOT MOHAVE ACTUALLY RECEIVED THE TRANSMISSION SERVICE?

A. No. His testimony does not raise any question regarding Mohave's utilization of the firm transmission service, the provision of the service or the rates charged. The sole basis for his recommended adjustment was the absence of Western invoices supporting the cost amount in the vast amount of documentation provided by

Mohave in response to Mr. Mendl's data requests. A major element of his review process apparently involved checking amounts charged to Mohave's PPCA against invoices – an activity the Staff asserts is done when the monthly reports are initially filed. See Staff Response to MWS-2.11 attached as CNS-Rebuttal Exhibit 1.

Q. HAS MOHAVE SUBSEQUENTLY PROVIDED THE REQUESTED INVOICES?

A. Yes. Reference CNS - Rebuttal Exhibit 2 which is a copy of Staff's response to MWS-2.6. Mohave also believes the invoices were initially submitted with its monthly fuel bank reports, but has not taken the time to locate and review its original filings, since ACC Staff is no longer proposing the adjustment.

4. MR. MENDL'S RECOMMENDATION TO REDUCE THE PURCHASED POWER BANK BALANCE BY $1.946 MILLION IS AN UNSUPPORTED SANCTION AND SHOULD BE REJECTED

Q. WHAT IS THE NATURE OF THE $1.946 MILLION ADJUSTMENT PROPOSED BY MR. MENDL?

A. Mr. Mendl characterizes the amount as a prudence adjustment (page 28, line 10; page 33, line 5; page 47, line 19), but as I will explain, it is imposed as sanction for Mohave's timely exercise of its right to object to unduly burdensome and questionably relevant data requests. It is a calculated amount equal to 1% of Mohave's entire purchased power costs reported in its monthly fuel bank reports submitted to the Commission during the period August 1, 2001 through December 31, 2006. Mr. Mendl recommends Mohave be required to refund this amount to Mohave's owner/member/customers through its PPCA. Mohave is discussing this recommendation with Staff and hopes to resolve it prior to hearing.

Q. WHAT IS THE BASIS FOR THIS SANCTION/ADJUSTMENT?

A. Mr. Mendl states that the adjustment is appropriate "because MEC failed to maintain and provide the information to support the prudence of its purchased power." Reference Direct Testimony of Jerry Mendl, p. 27, lines 16-17. No other basis for the proposed $1.946 million adjustment is provided.

Q. DO YOU HAVE PERSONAL KNOWLEDGE OF DISCUSSIONS WITH STAFF ON ISSUES RELATED TO THE PPCA MONTHLY REPORTING PROCESS?

A. Yes. I participated in a meeting on January 28, 2004, with Mohave and ACC Staff at which time we discussed supporting data for the PPCA. That particular meeting focused on treatment of third-party sales. However, I reference the meeting to illustrate Mohave's efforts to work with Staff to make certain they have the information needed to ensure that costs for purchased power are accurately calculated and documented.

Q. DID MOHAVE FAIL TO MAINTAIN ANY INFORMATION THE COMMISSION HAS REQUIRED IT TO MAINTAIN?

A. No. Mohave regularly submitted its monthly fuel bank reports to the Commission, including invoices to support its power purchase costs. "The purpose of the monthly purchase power report is to track and monitor a utility's purchase power bank balance and ensure the costs of purchased power are accurately calculated *and documented*." (Italics added) See Staff Response to MWS-2.11 attached as CNS-Rebuttal Exhibit 1.

Q. DID MOHAVE FAIL TO PROVIDE STAFF MONTHLY REPORTS RELATING TO ITS PURCHASED POWER FOR THE PERIOD JULY 25, 2001 THROUGH DECEMBER 31, 2006?

A. No. CNS-Rebuttal Exhibit 3 (Staff Response to MWS-2.36) shows that Staff received the reports for this time period. Mohave occasionally receives requests from the Staff to clarify or file additional information if the Staff has questions or finds that a particular report is missing or insufficient. To my knowledge, Mohave has never refused to provide any additional or missing information requested by Staff in relation to the monthly power purchase reports.

Q. THEN WHAT IS THE BASIS OF MR. MENDL'S ASSERTION THAT MOHAVE FAILED TO MAINTAIN AND PROVIDE INFORMATION TO SUPPORT ITS PURCHASED POWER?

A. Apparently, it is Mohave's exercise of its right to object to burdensome and questionably relevant data that is the sole basis of Mr. Mendl's recommendation of a $1.946 million adjustment/sanction.

When Mohave unexpectedly received data requests seeking voluminous power purchase information for the period July 2001 through 2010, it timely objected as permitted by Commission rules and the Procedural Order, dated July 15, 2011, governing this proceeding. The formal basis of the objection is set forth in a letter dated September 8, 2011, a copy of which is attached as CNS-Rebuttal Exhibit 4. Without waiving its objections, Mohave provided Staff an extensive confidential narrative setting forth the nature of its purchase power procedure and purchases since July 2001, and all supporting invoices encompassing the period January 1, 2007 through 2010. Reference JEM-2 Confidential. Mohave also provided some additional historical information, such as the historical Mead Index monthly on-peak and off-peak prices for the period January 2001 through December 2010 (Reference JEM-14 Confidential, which is Mohave's response to JM-3.64).

Preparation of these responses to the questions, and providing documentary support related to the January 1, 2007 through 2010 period, required significant time and effort by Mohave's employees, attorneys and outside consultants, as well as extensive effort on the part of Mr. Mendl to review and analyze. Reference CNS-Rebuttal Exhibit 5 (Staff Response to MWS-2.34). It should be noted that Staff also needed an additional 45 days to complete its review of the data supplied, thereby delaying a hearing on Mohave's application and its needed rate relief.

Q. IN YOUR OPINION WAS IT REASONABLE FOR MOHAVE TO ASSUME THAT DETAILED DOCUMENTARY SUPPORT FOR ITS PURCHASED POWER COSTS FOR THE PERIOD JULY 2001 THROUGH DECEMBER 31, 2006, WAS AVAILABLE TO MR. MENDL AND THAT STAFF WOULD MOVE TO COMPEL PRODUCTION OF ANY MISSING INFORMATION?

A. Yes. Mohave had previously provided the detailed support for these costs to Staff on a monthly basis and had responded to any requests for additional information. Therefore, it was reasonable for Mohave to assume that Mr. Mendl had independent access to this data and that Staff would move to compel production of any missing support.

Q. DID STAFF SEEK TO COMPEL MOHAVE TO PROVIDE ANY OF THE DATA THAT IT OBJECTED TO PROVIDING AS PERMITTED BY THE COMMISSION RULES AND THE JULY 15, 2011, PROCEDURAL ORDER?

A. No.

Q. WHY DO YOU REFER TO MR. MENDL'S PROPOSED $1.946 MILLION ADJUSTMENT AS A SANCTION?

A. Because the purpose is to penalize Mohave for timely *objecting* to a portion of the data requests he crafted and to avoid sending "a signal that a utility can avoid scrutiny by failing to maintain records and file requested information." Reference Direct testimony of Jerry Mendl, p. 27, lines 11-12.

Q. DOES MR. MENDL HAVE ANY BASIS FOR RECOMMENDING THAT A PRUDENCE ADJUSTMENT IS APPROPRIATE BASED ON INADEQUACY OF THE INFORMATION PROVIDED?

A. No. CNS-Rebuttal Exhibit 6 is response to MWS-2.29(a) which asked for this information. The response is not yet complete with regard to certain elements of the question. However, the response to (c) references a lack of supporting invoices as specified in Mr. Mendl's testimony. But Mr. Mendl has not provided Mohave any listing of specific data that was not provided or was missing when Mohave submitted its PPCA monthly reports for the period July 25, 2001 through December 31, 2006.

Q. IS IT CLEAR THAT MR. MENDL WAS PROVIDED ALL OF THE MONTHLY PPCA REPORTING DATA SUBMITTED TO THE ACC BY MOHAVE FOR HIS AUDIT?

A. Yes. CNS-Rebuttal Exhibit 7 is copy of Staff's response to MWS-2.24 which indicates Mr. Mendl was provided copies of the monthly purchased power adjustor reports.

Q. IS THERE A LIST IN MR. MENDL'S TESTIMONY IDENTIFYING SPECIFIC MONTHS OR DATA THAT WERE MISSING OR NEEDED FURTHER EXPLANATION TO SUPPORT THE PPCA MONTHLY REPORT?

A. No. Mr. Mendl's testimony, as well as the data requests received by Mohave only reference the entire sixty five (65) month period. In responding to a question about conclusions regarding prudence during this period he states "....MEC objected to providing information prior to 2007. .... Therefore Staff can make no determination regarding the prudence of MEC's power purchases prior to 2007." (Reference Direct testimony of Jerry Mendl, p. 26, line 19).

Q. WHAT IS MOHAVE'S REBUTTAL POSITION WITH REGARD TO PROVIDING REQUIRED DATA TO SUPPORT THE PPCA BANK?

A. Mohave has fully documented all purchased power expenses for the 2007 through 2010 period in responses to data requests in this proceeding. In addition, Mohave provided monthly reports for the 2001 through 2010 period. Mohave further acknowledges the requirement to provide Staff adequate supporting data of its purchased power costs with its monthly filings and to timely supplement that information when requested by Staff. Having done so, it is unreasonable and arbitrary to require Mohave to produce that same data during a rate proceeding or independent proceeding so Staff can conduct an independent prudency review of Mohave's purchase power practices. In the event Staff conducts an independent review of those monthly reports and identifies specific gaps in the documentation Mohave previously supplied, then Mohave should and will commit to make a reasonable effort to provide documentation in order to address those specifically identified gaps in information. However, Staff and Mohave have a joint responsibility to verify the completeness of the monthly reports when submitted. CNS Rebuttal Exhibit 1 and CNS Rebuttal Exhibit 1A, response to MWS-2.11 clearly identifies this process.

Q. IS THERE ANY COMMISSION RULE OR ORDER OR AN ACCOUNTING PRINCIPLE THAT REQUIRED MOHAVE TO MAINTAIN DOCUMENTATION OF ITS PURCHASED POWER COSTS FOR MORE THAN FOUR (4) YEARS?

A. I know of none and Staff has not identified any.

Q. HOW WAS THE ADJUSTMENT OF $1.946 MILLION PENALTY DETERMINED?

A. The value is equal to 1% of the total wholesale power cost for the period July 25, 2001 to December 31, 2006, of $194.681 million. Reference direct testimony of Jerry Mendl, p. 28, lines 4-11.

Q. WHY DID MR MENDL USE A 1% FACTOR?

A. Mr. Mendl does not state the basis for the 1% value. Attached is CNS-Rebuttal Exhibit 8 (Response to MWS-2.28) which indicates that values of 0% up to 100% were considered by Staff.

Q. WHAT IS THE AUTHORITY FOR PROPOSING THE PRUDENCE ADJUSTMENT?

A. Mohave's data request MWS-2.28(d) asked Staff to "identify any authority upon which Staff relied in developing its $1.946 million (1%) prudence adjustment recommendation." As of the filing of this rebuttal testimony, Staff has not provided any.

Q. WHAT IS THE REASON FOR USING THE TOTAL PURCHASED POWER COST OF $194.681 MILLION (PAGE 28, LINE 9) IN THE CALCULATION OF THE PRUDENCE ADJUSTMENT?

A. Again, Mr. Mendl does not state why he applies the 1% factor to the total purchased power cost incurred by Mohave for the period July 25, 2001 to December 31, 2006. The total includes power costs incurred by Mohave for payments under ACC approved rates to AEPCO and also includes transmission costs. However, in response to MWS-2.30, Staff acknowledged it is not its position that a prudency penalty should be paid for amounts paid to AEPCO or others at ACC approved rates. See CNS-Rebuttal Exhibit 9 (Response to MWS-2.30).

Q. DID MR. MENDL INDICATE THE APPROPRIATE FACTOR THAT WOULD BE APPLICABLE FOR THAT PORTION OF THE POWER COST THAT WAS EITHER PURCHASED AT MARKET RATES OR THAT PORTION OF THE AEPCO COST THAT MOHAVE COULD HAVE REPLACED WITH MARKET PURCHASES?

A. No. In response to data request MWS-2.30, Staff merely suggests such calculation was precluded due to a lack of information supplied by Mohave. Staff does not explain why the information was unavailable from the monthly reports Mohave had submitted and it provided to Mr. Mendl. Given the fact that Staff considered values ranging from 0% to 100%, it is fair to assume Staff arrived at a value it believed sent the intended signal that a utility cannot avoid scrutiny by failing to maintain requested file data, even though it presented no evidence Mohave had failed to maintain or file data. In reality, Staff is recommending a $1.946 million sanction be imposed on Mohave for timely objecting to re-submitting data 5 to 10 years following *its initial submittal with Staff.*

Q. DOES MR. MENDL SPECIFICALLY CONCLUDE THAT MEC'S PURCHASED POWER COSTS BETWEEN 7/25/2001 AND 12/31/2006 WERE IMPRUDENT?

A. No. When asked what the Staff concluded about the prudence of Mohave's power cost during this period, his answer is "Nothing." (Reference direct testimony of Jerry Mendl, p. 26, line 19.)

Q. GIVEN THE FACT THAT MR. MENDL WAS NOT ABLE TO COME TO A CONCLUSION ABOUT PRUDENCE, DOES HE PROVIDE ALTERNATIVES TO DEAL WITH THE PRUDENCE OF MOHAVE PURCHASED POWER COSTS BETWEEN 7/25/2001 AND 12/31/2006?

A. Yes. He lists three options beginning on page 27 of his testimony. The options are:

1. The Commission could direct MEC to file the needed information. As discussed above, Staff had this option but did not pursue it. This may be based on Mr. Mendl's unilateral determination that "it is likely that the requisite information is no longer available. Even if MEC provided its purchased power information, it would also have to reconstruct the context of the market and other parameters in that time period. Doing this option would be at best time consuming and burdensome [the precise basis of Mohave's objection], if even possible." As discussed earlier, Staff has never identified which of the sixty five (65) months required additional supporting data, yet the penalty (prudence adjustment) is applied equally to all power purchases over the entire sixty five (65) month period, suggesting all months were of equal concern.

2. The Commission could accept the costs reported for the period July 25, 2001 through December 31, 2006, as prudent. He rejects this option as sending a signal that a utility can avoid scrutiny by failing to maintain records and file requested information, which, as discussed, is not consistent with Mohave's actions. However, this option is actually supported by the facts. The four-year period for which Mohave re-submitted purchase power documentation, of the more than $54 million in annual purchased power costs claimed by Mohave, not a single expense remains undocumented and only $32,702 is

being completely disallowed. From this evidence, it is reasonable to conclude that Mohave does maintain documentation for all of the purchase power costs it claims in its monthly reports.

3. The Commission could impose a 1% prudence adjustment, based upon the unsupported accusation that MEC failed to maintain and provide the information to support its purchased power cost.

Mr. Mendl and Staff adopted option #3 as a signal to Mohave and other utilities that they should not try to avoid Commission scrutiny.

Importantly, Mohave has never asserted it is immune from Commission scrutiny or has no obligation to maintain and file documentation supporting its purchased power costs. The sole question is whether it is reasonable to penalize Mohave $1.946 million for timely objecting to Staff's broad request, during this rate proceeding, that Mohave resubmit data going back 5 to 10 years without indicating what specific information had not been submitted with its monthly purchased power reports, where:

- No Commission rule or order or accounting principle mandates retention of such documentation for such a prolonged period;
- Mohave regularly submitted its monthly reports (CNS-Rebuttal Exhibit 3 (response to MWS-2.36) indicates Staff did receive information from Mohave);
- Staff acknowledges that the purpose of the monthly purchase power reports is to allow Staff to track and monitor a utility's purchase power bank balance and ensure the costs of purchased power are accurately calculated *and documented* (CNS-Rebuttal Exhibit 1 (response to MWS-2.11));
- Mr. Mendl was provided the monthly reports (CNS-Rebuttal Exhibit 5 (response to MWS-2.24)), but did not identify any specific data that was missing; and
- The documentation that has been provided demonstrates Mohave does maintain that appropriate documentation.

In my opinion imposing any penalty under the facts of this case is unreasonable. Applying a blanket percentage against all purchased power costs incurred during the period is arbitrary and unduly penalizes this electric distribution cooperative for exercising its right to object to burdensome data requests. To suggest Mohave is not maintaining or has not responded to reasonable requests for information is simply not true. As I indicated previously, Mohave staff and ACC Staff met in 2004 where Mohave described the change from an All Requirements Class A Member of AEPCO ("ARM") to a Partial Requirements Member of AEPCO ("PRM"), explained the treatment of costs, including third-party sales, explained the reports Mohave intended to file, and sought feedback from Staff as to the adequacy of the proposed treatment of the PPCA bank. To my knowledge Mohave has always provided data requested by Staff to support the PPCA.

Q. DO YOU BELIEVE THERE ARE ADDITIONAL REASONS TO REJECT STAFF'S RECOMMENDATION OF A $1.946 MILLION PENALTY (PRUDENCE ADJUSTMENT)?

A. Yes. Mr. Mendl references Exhibit JEM-15 in coming to conclusions about the prudence of Mohave's purchased power cost for the period following 12/31/2006. The exhibit also shows data for the period July 2001 to 2007. The exhibit shows MEC's Average Cost, excluding transmission, was competitive with Mead On-Peak and Off-Peak prices (provided by Mohave in Data Response Attachment JEM-3.64). In fact, Mohave was more competitive during this period than the period post July 2008, which Mr. Mendl found to be reasonable. This data supports the notion that Mohave's actual implementation of the power supply strategy resulted in competitive rates.

Mr. Mendl also makes a specific recommendation to "Acknowledge that MEC's selection and management of Western to provide critical services are prudent and reasonable" (page 33, line 22). Western has had active involvement and has played essentially the same role for Mohave since Mohave first became a PRM. I believe it is reasonable to assume that Western's actions for the period 2001-2006 resulted in the same prudent decisions as for the period 2007-2010. Exhibit JEM-15 data supports this conclusion.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS RELATED TO THE PRUDENCY ADJUSTMENT PROPOSED BY MR. MENDL.

A. Mohave does not oppose filing data to support the purchased power adjustment bank and Mohave is not seeking to avoid scrutiny. Mohave has filed data in support of the costs included in the purchased power bank since its inception. Mohave also met with the Commission Staff to review data that would be filed after becoming a PRM to make certain the required information was being provided.

Mohave generally agrees with Mr. Mendl's conclusion regarding the relative difficulty of reconstructing, in 2011 or 2012, events that occurred in the 2001-2006 period due to the absence of detailed market data.

Mohave believes that Mr. Mendl has done a good job in reconstructing cost and market relationships in prior periods with his Exhibit JEM-15, page 1. Mohave believes that this analysis indicates the strategy as reflected in actual power cost would clearly not support an imprudence finding.

Mohave appreciates the time and effort Mr. Mendl has spent in understanding Western's role in the power supply acquisition and implementation process. Mohave places great value on Mr. Mendl's conclusion that involving Western's services was prudent and reasonable. Western has been involved since 2001 and continues to be an integral part of the team.

Staff provided Mr. Mendl with data for the 65-month period from August 2001 to December 2006; data which Staff indicates it had already reviewed in order to ensure the monthly power purchase costs reported were accurately calculated and reported.

For these reasons I have stated, Mohave does not believe the $1.94 million prudence adjustment is supported by the facts in this proceeding.

5. MR. MENDL'S RECOMMENDATION TO REDUCE THE PURCHASED POWER BANK BALANCE BY $ 594,737 IS UNSUPPORTED AND SHOULD BE REJECTED

Q. WHAT IS THE NATURE OF THIS ADJUSTMENT?

A. During the 2010 test year, Mohave incurred $594,737 in purchased power activities that it included in its PPCA bank balance and that Mr. Mendl characterizes as ineligible costs. These costs involved outside consulting and legal costs, as well as Mohave staff's costs associated with securing, scheduling, documenting and reporting purchased power.

Q. ARE THE COSTS INELIGIBLE BECAUSE THEY INCLUDE COSTS THAT SHOULD NOT BE PAID BY THE RATE PAYER?

A. No. Staff has reclassified $562,035 of the $594,737 as administrative and general expenses for recovery in base rates. Staff recommends disallowing $32,702 of the costs associated with efforts relating to federal Hoover power remarketing legislation. Mohave does not contest this part of the adjustment, while not conceding it is appropriate. Therefore, the question is how the $562,035 should be recovered, i.e., as part of the PPCA as proposed by Mohave or part of the base rates as proposed by Staff.

Q. WHAT APPEARS TO BE THE BASIS FOR DETERMINING WHETHER THE COSTS SHOULD BE RECOVERED THROUGH THE PPCA OR BASE RATES?

A. Mr. Mendl suggests two criteria.

1. Whether the costs are within the control of the utility. If the costs are within the control of the utility, they should be recovered through general rates (page 15, line 6).

2. Whether the costs are subject to volatile change (page 15, line 4 and line 12). If the costs are volatile (like fuel prices) they can be included in an adjustor.

Q. DO YOU AGREE WITH MR. MENDL'S RECOMMENDATIONS AS TO THE APPLICABLE CRITERIA FOR DETERMINING HOW COSTS SHOULD BE RECOVERED?

A. Yes, I believe his criteria-related volatility/predictability and control are appropriate. Mohave's primary objective in the development of retail rates is to recover only the cost of providing service to the retail member-consumer. Mr. Mendl's criteria are an important part of deciding how best to accomplish this objective.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE TO RECOVER THE $562,035 IN PURCHASED POWER RELATED COSTS THROUGH THE PPCA RATHER THAN BASE RATES?

A. I believe these purchase power related costs track both of Mr. Mendl's criteria. First, I agree there is a portion of the costs that are predictable; however, there is also a component of the costs (particularly those related to outside services) that are volatile and unpredictable. For example, the level of costs is driven by:

1. When AEPCO and SWTCO have a rate proceeding before the ACC. The timing for the AEPCO rate cases, the complexity of the cases, and the level of effort required are not readily defined.
2. AEPCO may have a special filing with the ACC such as the recent fixed fuel adjustor filing.
3. Mohave must deal with potential legislative actions that can adversely impact the hydro allocation.
4. Market conditions will require differing levels of effort to track costs and take advantage of market purchases.
5. Mohave will evaluate power supply alternatives when they come up.

The point is that the volatility that Mr. Mendl references is a fact of life for Mohave, as staff and consultants manage power supply issues.

With regard to management control, while Mohave's management and Board have some control over the level of staff costs and outside costs associated with dealing with power supply issues, the level of involvement is driven by the significant portion of Mohave's total cost of service represented by power supply costs. While Mohave could decide not to participate in a particular filing, hearing, litigation, power supply plan, etc., its failure to actively represent its members' interest in maintaining a reliable and low cost wholesale power supply would not be seen as prudent by the Commission. Therefore, the level of activity is to a large extent driven by external factors over which Mohave has no direct control. Since these costs are also directly related to securing, scheduling, and documenting and reporting purchased power, it is appropriate to record them as purchased power costs and recover them under the PPCA.

Q. WHAT IS YOUR RECOMMENDATION IF THE STAFF PROPOSAL IS ADOPTED?

A. If the Staff recommendation to include cost recovery in the base rates is adopted, then the costs in question should continue to be covered in the PPCA until the revised rates go into effect. On the effective date of the new rates, the costs should be excluded from the PPCA. The costs should not be included in the prudence adjustment because this would result in refund to the consumers of costs that the Commission has determined to be recoverable.

Q ARE THERE ANY OTHER REASONS IT IS APPROPRIATE TO CONTINUE TO RECOVER THE COSTS IN THE PPCA UNTIL THE EFFECTIVE DATE OF THE NEW RATES?

A. Yes. The current base rates were designed prior to Mohave transitioning to partial requirement status. Therefore, there are no power supply support costs in the existing Mohave base rates and it is appropriate to recover these costs through the PPCA until such time as they are transferred (assuming Staff's recommendation is adopted) to the base rates.

Q. WAS MR. MENDL CRITICAL OF MOHAVE'S NOT INCLUDING THE POWER SUPPLY SUPPORT CHARGES IN THE PPCA UNTIL JANUARY 1, 2010?

A. Yes. As Mr. Mendl recognizes, Mohave has been evolving as to its purchase power practices since its conversion to a PRM in 2001. Prior to 2008, Mohave did not specifically record legal, consulting and staff expense that was dedicated to purchase power activity. Additionally, it had sufficient margins from third-party sales to support these activities. During 2008 and 2009, Mohave refined its documentation of these costs and how they were booked. By 2010, appropriate procedures had been implemented to document and book these costs as power purchase costs so they could be submitted, with necessary documentation, under its PPCA. This action also assisted Mohave in addressing substantially eroding margins, in part due to the decrease in margins made from third-party sales. Contrary to Mr. Mendl's testimony, Mohave had not intentionally excluded these costs from the PPCA prior to 2010. Mohave did not have them properly segregated and documented and there was less of a need to recover them prior to 2010.

6. <u>OTHER CONSIDERATIONS RELATED TO MR. MENDL'S RECOMMENDATION TO REDUCE THE PPCA BANK BALANCE</u>

Q. WHAT IS THE TOTAL AMOUNT BY WHICH MR. MENDL RECOMMENDS THAT THE PURCHASED POWER BANK BALANCE BE ADJUSTED?

A. The total adjustment is $2.704 million (reference p. 46, line 3) and consists of the three components described above:

Adjustment for unsupported 2008 power cost:	$ 163,221
Adjustment to reflect imprudence penalty:	$ 1,946,000
Adjustment for ineligible power supply-related costs:	$ 594,737
Total	$2,703,958

My understanding is that Staff has accepted the documentation for the 2008 power cost and I assume the recommended reduction is now approximately $2.54 million. Mr. Mendl also recommends that the PPCA bank balance be adjusted to reflect additional legal, consulting and staff purchased power-related costs included in the PPCA bank balance from the end of the test year to when new rates are effective. The actual amount is currently unknown, but it can be expected to meet or exceed the $562,065 incurred in 2010. Therefore, the total adjustment is estimated to be $3,102,802.

Q. ARE THERE FACTORS THE COMMISSION SHOULD CONSIDER IN EVALUATING THE REASONABLENESS OF MR. MENDL'S RECOMMENDATION?

A. Yes. There needs to be an understanding as to how not only Mohave but also the member-consumers will be impacted by reductions in the PPCA bank balance. My understanding, based on Mohave's discussions with its auditor, is that there will be the following accounting adjustments made in the year in which the new rates go into effect (I am assuming this will be 2012) to reflect Mr. Mendl's recommended write-off. The adjustments include:

1. Income Statement:
    a. Total revenue will be reduced to reflect the amount of the write-off.
    b. Operating Income will be reduced to reflect the amount of the write-off.
    c. Net income will be reduced by the amount of the write-off.
    d. Coverage ratios (TIER and DSC) will be reduced by the amount of the write-off.
2. Balance Sheet:
    a. Equity will be reduced by the amount of the write-off.

b. Current and Accrued Liability will be increased by the amount of write-off.

3. Member Patronage Capital Accounts:

a. Member patronage will be reduced by the amount of the write-off (subject to any other applicable limitation).

Q WHAT ARE THE IMPLICATIONS OF THESE ADJUSTMENTS RESULTING FROM MR. MENDL'S RECOMMENDATION?

A. The consequences include:

1. The Income Statement Impact: The adjustment will result in completely eliminating any increased revenue associated with approved rates in 2012. As a result, Mohave will be in default of its mortgage coverage requirements. This means Mohave will be in default of the mortgage requirements for the last four years. RUS requires the Cooperative to maintain OTIER coverage greater than 1.10 for two of the last three years. CNS-Rebuttal Exhibit 10 shows the OTIER values of:

2009	0.32
2010	0.19
2011	(0.12) est

CNS-Rebuttal Exhibit 10 shows the impact assuming the Staff revenue requirement for the 2010 test year and assuming the rates are in effect for a full twelve months and the Staff adjustment of $3.1 million is adopted. The resulting OTIER is 0.42. Given that the proposed rates will not be in place for a full twelve months, Mohave will clearly be in default of the mortgage requirements and this will be the 4th consecutive year of default.

2. The Balance Sheet Impact: The adjustment will result in a reduction in the equity.

3. The Patronage Capital Impact: The adjustment will mean the patronage capital assigned to all member-consumers will be reduced.

Q. TYPICALLY, THE NOTION OF A PENALTY APPLIED TO A UTILITY SUGGESTS THAT SOME THIRD PARTY WILL BE IMPACTED AND NOT THE RATE PAYERS. IS THIS THE CASE WITH THE ADJUSTMENT PROPOSED BY MR. MENDL?

A. No. There is no third party. There are no stockholders. The member-consumer is the owner of the Cooperative and is directly impacted by the adjustment. The Cooperative needs access to funds for capital expenditures to serve the member-consumers, the adjustment puts this at risk. It is in the Cooperative's interest to maintain adequate equity— the adjustment will adversely impact the equity. The member's patronage capital accounts will be reduced.

As described above, Mohave does not believe the prudency adjustment related to the 2008 period, the 2001-2006 period, or the power supply-related costs is justified or appropriate. Any suggestion that this is in the best interest of the retail member-consumers served ignores the business model of a cooperative.

Q. DID THE STAFF ADDRESS THE FINANCIAL IMPACT ISSUE?

A. Not in direct testimony. However, in response to data requests when asked about the financial impact of the prudence adjustment, Staff indicated that for Staff's calculation of cash flow, TIER, and DSC there would be no impact of a prudence adjustment that would be recorded below the line – <u>CNS- Rebuttal Exhibit 11</u> (MWS-2.32).

Q. DO YOU AGREE?

A. As mentioned earlier, Mohave has had discussions with their auditor as to how the adjustments would be reported. The auditor indicates that assuming prior period financials did not have to be restated, that the prudence adjustment would be made to revenue and would impact the income statement and balance sheet as I have described above. I am not an accountant and it would be important for Staff and Mohave accountants to discuss this issue. One very important point, however, is Staff does recognize that even with the Staff assumptions, the RUS/CFC financial ratios would be impacted. See <u>CNS-Rebuttal Exhibit 11</u> (Response to MWS-2.32). RUS and CFC are the lenders to Mohave. A cooperative is obligated to meet coverage ratios based on both OTIER and Net TIER which include both operating margins and net margins. The retail member-consumers served by Mohave are also Mohave's owners and will be directly impacted not only in terms of current financials but more importantly in terms of the ramifications of not having debt financing available. This can only lead to higher rates for Mohave.

7. IT IS APPROPRIATE TO CREDIT THE PPCA BANK BALANCE WITH COST OF SALES TO THIRD-PARTY SALES AND ALLOCATE MARGINS TO THE BENEFIT OF ALL MEMBERS

Q. WHAT IS THE ISSUE RELATED TO THE PPCA TREATMENT FOR THIRD -PARTY SALES?

A. The issue is whether the PPCA bank should receive a credit in the amount of cost associated with making third-party sales or with the total revenue associated with third-party sales. Mohave has historically credited the PPCA bank with the cost of the third-party sales and reported the revenues as income, with the margins reflected in the income statement. This is consistent with the discussion Mohave had with Staff in January 2004. Staff is now recommending that the total revenue be credited to the PPCA bank.

Q. WHAT IS THE DIFFERENCE BETWEEN THE TWO ALTERNATIVES?

A. In explaining the difference, it is important to keep in mind that the revenue from a third-party sale consists of two components:

1. The cost associated with making the sale. The cost typically consists of energy cost and sometimes a transmission cost.

2. The margin associated with the sale. The margin is the amount the third-party is willing to pay less the cost incurred in making the sale.

Mohave's approach is to credit the PPCA with the cost of making the third-party sale. As a result, the retail member-consumers are not charged any cost associated with making a third-party sale. Mohave then flows through the margins earned from third-party sales to the net income. The Staff proposal credits to the PPCA the total revenue associated with the third-party sale.

Q. DOES THE STAFF PROPOSAL RESULT IN A LOWER PPCA BANK BALANCE AS COMPARED TO MOHAVE'S METHODOLOGY?

A. Yes, the difference is typically the amount of the margin. Mohave's methodology ensures that the PPCA is always credited with the cost of the transaction so the retail member-consumer is never at risk.

Q. DOES THE RETAIL MEMBER-CONSUMER BENEFIT FROM THE MARGIN UNDER MOHAVE'S METHODOLOGY?

A. Yes, the retail member-consumer benefits as follows:

1. Increases the margins resulting in higher coverage ratios
2. Flows to equity and increases the equity ratio for the Cooperative
3. Flows to the member's patronage capital account which increases the equity each member has in the Cooperative

The retail member-consumer benefits in that the margin component is allocated as part of patronage capital, the Cooperative is able to realize a stronger financial basis, and, depending on how rates and costs perform, it is possible margins from third-party sales can postpone the need for base rate increases.

Q. DOES THE STAFF METHODOLOGY ACCOMPLISH ANY OF THESE OBJECTIVES?

A. No. The Staff alternative credits the total revenue of the third-party sale to the PPCA bank. This results in a lower PPCA bank balance. However, because the total amount is a credit to the PPCA bank balance, there is no contribution to an increase in coverage ratio, equity or allocated patronage capital account.

Q. WITH THE STAFF METHODOLOGY, WHO WILL GET THE BENEFIT OF THE MARGINS ASSOCIATED WITH A THIRD-PARTY SALE IN A PARTICULAR MONTH?

A. The benefit flows to those member-consumers who are taking service in the month in which the third-party sale is made. Typically, these are off-peak months.

Q. DOES THIS RESULT IN SOME INEQUITIES IN YOUR OPINION?

A. Yes. Mohave is able to make third-party sales because they have the assets in place to make the sale. Most of the sales are a result of excess AEPCO Base Resource energy. The excess sales occur during those months in which Mohave's retail load is low and excess energy is available. However, Mohave's member-consumers pay the fixed costs for the asset as a part of the rate each month of the year. In fact, a large part of the fixed costs is covered during the peak usage month. These are the very months in which there is little or no excess Base Resource energy available for third-party sales. Therefore, with the Staff methodology there is a disconnect between payment of fixed costs and receipt of margins realized from utilization of the asset.

Q. HOW DOES MOHAVE'S METHODOLOGY PROVIDE A MORE EQUITABLE ALIGNMENT OF COSTS AND BENEFITS?

A. Mohave explicitly recognizes the margin component. The margin component flows to the benefit of all members by increasing earnings, coverages and equity. The margins are allocated to individual members-consumers based on business done with the Cooperative. This provides a better alignment with allocation of benefits to those members that are paying for the assets that create the benefits.

Q. ARE THERE ANY OTHER FACTORS THE COMMISSION SHOULD CONSIDER IN EVALUATING THE APPROPRIATE WAY TO DEAL WITH THIRD-PARTY SALES?

A. Yes, the methodology used by Mohave to deal with third-party sales in the calculation of the PPCA is not new or different. In fact, it is the same methodology that Mohave used for sales to another customer; it is a methodology that has been in place for a number of years; it is and a methodology that was reviewed with Commission Staff in January 2004.

Q. PLEASE EXPLAIN.

A. For many years, Mohave provided service to a large power customer. In establishing the purchased power cost applicable to the PPCA, Mohave subtracted from the total power cost the power cost associated with serving the large power customer. This isolated the other retail member-consumers from any wholesale power costs incurred in serving the customer. After Mohave became a PRM and had the opportunity to make third-party sales, we met with the Commission Staff in January 2004 and explained the situation. We proposed a treatment to deal with third-party sales that was exactly the same as that used for the large power load. We have been using the same methodology ever since Mohave became a partial requirements customer. To my knowledge, Staff has not previously raised any questions concerning treatment of the third-party sales.

8. MR. MENDL'S RECOMMENDATION THAT MOHAVE RECONSIDER THE LIMIT ON POWER PURCHASED FROM THE SPOT MARKET SHOULD BE REJECTED.

Q. WHAT IS THE NATURE OF MR. MENDL'S RECOMMENDATION?

A. As a PRM, Mohave is allocated 35.8% of AEPCO generation resources, and this allocation provides sufficient capacity and energy to serve Mohave's native load requirements in all months except summer months. Mohave fills the summer resource deficiency with a combination of block purchases and spot market purchases. One criterion for summer power supply planning is that not more than a certain percentage of Mohave's total monthly load (in summer months) is exposed to spot market. The reason for the criterion is to reduce Mohave's exposure to economic risk of volatile spot market prices. Mr. Mendl notes that in the past two years spot market prices have been stable and low and not very volatile. See Mendl's direct testimony at page 11, line 20. In fact, according to Mendl, spot market prices were less expensive than the block power Mohave purchased. He concludes that it is not reasonable to have an arbitrary limit on the amount of lower cost power Mohave could procure from the spot market. See Mendl's direct testimony at page 12, line 1 - 4.

Q. DO YOU DISAGREE WITH MR. MENDL'S ANALYSIS OF SPOT MARKET PRICES OVER THE PAST TWO YEARS?

A. No. It has been our experience that during some summer periods the actual spot price is lower than the block purchase made by Mohave and in some summer periods the actual spot price is higher than the block purchase made by Mohave.

Q. IF SPOT MARKET PRICES WERE LOWER THAN THE BLOCK PRICE, WHY DID MOHAVE MAKE THE BLOCK PURCHASE?

A. At the time of the block purchases, the block prices were made based on forward market prices for the summer. While the actual spot market prices turned out to be less than the forwards in place at the time of the block purchase, the reverse could equally have occurred. For example, an unplanned outage of a generation unit in the region could result in high spot market prices.

Q. EXACTLY WHAT IS MR. MENDL'S RECOMMENDATION?

A. Mr. Mendl recommends that Mohave reconsider its "arbitrary limit on the amount of spot market electricity it purchases to take advantage of potentially lower cost opportunities in the future and modify its policies of power supply planning and implementation accordingly." See Mendl's direct testimony at page 12, line 12.

Q. WHY SHOULD HIS RECOMMENDATION BE REJECTED?

A. Mr. Mendl's recommendation should be rejected for the following reasons. First, he erroneously characterizes the limit as a "policy." It is not a policy but simply a planning criterion which Mohave may change at any time. Mohave is not locked into an arbitrary limit. The fact that Mohave has not changed its summer planning criteria does not mean that the Cooperative has not reconsidered the criteria. Mohave has reconsidered and decided that the existing criterion is still valid. Second, if the spot market prices are less than AEPCO resource cost, Mohave has the ability to reduce the AEPCO resource and replace it with market purchases. Therefore, Mohave has additional flexibility to take advantage of market prices. Consequently, Mr. Mendl is making a recommendation that Mohave already has in place.

Q. ARE THERE ANY LIMITATIONS TO THE AMOUNT OF ENERGY THAT MOHAVE MUST PURCHASE FROM AEPCO?

A. Yes, there is a limitation: AEPCO Base Resource, which consists primarily of coal generation, has a minimum must-run level which is allocated to Members according to their Allocated Capacity. Mohave's allocated share is 35.8%. Should Mohave schedule less than its allocated AEPCO minimum Base Resource and purchase from a third party, Mohave is subject to a minimum take-or-pay requirement. Consequently, as a rule Mohave will not schedule below its allocated minimum Base Resource level. This limitation puts a constraint on how much Mohave can back down its AEPCO Base Resource schedule and replace with spot market purchases. In the summer months when Mohave has its maximum load requirement, however, the constraint is much less a factor than in the other months.

Q. COULD MOHAVE BACK DOWN THE ENTIRE AEPCO RESOURCE AND REPLACE IT WITH LOWER MARKET PRICES?

A. No. In the worst case scenario when AEPCO's total system requirement is less than AEPCO's minimum Base Requirement level, Mohave could not replace all of the AEPCO Base Resource with spot market purchases without incurring a take-or-pay penalty from AEPCO.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.11: Please explain the purpose(s) behind requiring the submittal of monthly purchase power adjustor reports and supporting invoices to Staff.

RESPONSE:

The purpose of the monthly purchase power report is to track and monitor a utility's purchased power bank balance and ensure that costs for purchased power are accurately calculated and documented.

RESPONDENT: Candrea Allen, Public Utilities Analyst II

**UTILITIES DIVISION STAFF'S RESPONSES TO
MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET
OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION
DOCKET NO. E-01750A-11-0136
FEBRUARY 17, 2012**

MWS-2.10: Please describe the nature and extent of Commission Staff's review of MEC's monthly purchase power adjustor reports, and supporting invoices, after being received by Staff.

RESPONSE:

Staff compiles the information received by a utility and inputs the data into a spreadsheet which is used to track and monitor the purchased power adjustor bank balance.

RESPONDENT: **Candrea Allen, Public Utilities Analyst II**

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.6: Please confirm that the Supplemental response to JEM-9.14 dated January 20, 2012 provides adequate support for the $163,221.69 for firm transmission services provided by WAPA in 2008, as referenced at page 19, lines 13 – 14 of Mr. Mendl's direct testimony and that Staff no longer recommends an adjustment to the fuel bank balance related thereto.

RESPONSE:

That is correct.

RESPONDENT: **Jerry E. Mendl, Consultant**

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.36: Please admit that MEC has submitted to Commission Staff monthly fuel bank reports, with supporting power purchase invoices, for each calendar month from January 2001 through December 2006. In the event you deny or otherwise do not admit the foregoing, please set forth all facts and provide any Information that support or contradict your response.

<u>RESPONSE</u>:

Staff did receive monthly purchased power reports and supporting invoices for the time period from January 2001 through December 2006. However, there were months during the January 2001 through December 2006 time frame when the filings that were submitted did not include all invoices for costs claimed by MEC (as required by Decision No. 50266).

RESPONDENT: Candrea Allen, Public Utilities Analyst II

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REFER TO FILE NO. 1234-18-8

September 8, 2011

Via Email only

Bridget Humphrey, Esq.
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: Mohave Electric Cooperative, Incorporated Rate Case Docket No. E-01750A-11-0136 – Objections to Staff's Third Set of Data Requests

Dear Bridget:

Mohave Electric Cooperative, Incorporated (Mohave) has received Staff's Second and Third Set of Data Requests dated August 30, 2011 and September 1, 2011, respectively. As we have noted in prior communications, Mohave does not maintain a separate staff to process rate cases. Therefore, Mohave's employees remain responsible for performing their regular duties, in addition to responding to data requests received related to the pending rate case. Mohave intends to remain cooperative and responsive to legitimate Staff inquiries, to avoid unnecessary discovery disputes, and to otherwise facilitate the prompt processing of its rate case. However, Mohave objects to numerous broad, burdensome and irrelevant data requests included within Staff's Third Set of Data Requests, prepared by Mr. Jerry Mendl of MS Energy Associates, Inc.

These data requests seek information related to Mohave's power purchases and power purchasing practices for the last decade (i.e., prior to and after the Commission expressly authorized Mohave's conversion to a Partial Requirements Member (PRM) of the Arizona Electric Power Cooperative (AEPCO) pursuant to Decision No. 63868, dated July 25, 2001). Importantly, not only do these requests seek a large amount of detailed information involving periods well outside of the test year ending December 31, 2009 that would be extremely burdensome if not impossible to gather, the Commission's Decision No. 72055, dated January 6, 2011 renders the bulk of the information of limited or no value in accessing Mohave's current and future power purchasing practices.

By Decision No. 72055, the Commission approved new and revised contracts between AEPCO and its PRMs, Mohave, Sulphur Springs Valley Electric Cooperative, Inc., and Trico Electric Cooperative, Inc., as well as a revised all requirements agreement between AEPCO and its ARMs, Duncan Valley Electric Cooperative and Graham County Electric Cooperative. These new and revised contracts substantially alter the manner in which AEPCO's costs are allocated among its ARMs and PRMs and thus the rates and charges AEPCO is authorized to charge the ARMs and PRMs. Moreover, even prior to the Commission's approval of the latest round of new and amended ARM and PRM contracts, the Commission had also approved intermediate new and amended contracts that impacted Mohave's relationship to AEPCO and other members of AEPCO. See, Decision No. 70105, dated December 21, 2007 (where the Commission approved SSVEC's conversion to a PRM).

Mohave therefore objects to the data requests specifically listed below as unduly burdensome and irrelevant:

JM-3.7 d), e) and f); JM-3.8; JM-3.15 (all subparts); 3.16 (all subparts); JM-3.17 (all subparts); JM-3.19; JM-3.20; JM-3.22; JM-3.23; JM-3.25; JM-3.27; JM-3.29; JM-3.31; JM-3.33; JM-3.34 (all subparts); JM-3.38; JM-3.39; JM-3.40; JM-3.41; JM-3.42; JM-3.44; JM-3.48 through JM-3.51 (all subparts); JM-3.53; JM-3.55 through JM-3.58; JM-3.60; JM-3.62 - JM-3.72; JM-3.74 and JM-3.76;

In an effort to minimize disputes with Staff, and without waiving its objection to the specific data requests listed above, Mohave notifies Staff of its intent to provide a narrative generally describing its present and past relationship with AEPCO and power purchasing practices. To the extent maintained and reasonably retrievable by Mohave, Mohave will also provide information regarding its power purchases for the period commencing January 1, 2007 through December 31, 2009 in response to specific data requests. Mohave is still evaluating whether and to what extent additional time may be necessary to respond to Staff's Third Set of Data Requests. As you know, the Third Set of Data Requests was emailed two days after Staff emailed its Second Set of Data Requests. The standard 10 calendar day response period for both sets of data requests included the Labor Day holiday. Mohave expects to be able to provide responses to the Second Set of Data Requests no later than 4 p.m. Friday, September 9, 2011 (the 10th calendar day after electronic receipt). However Mohave asks that Staff grant Mohave until Monday, September 19, 2011 to provide its initial response to Staff's Third Set of Data Requests. Also, Mohave requests a Protective Agreement with Staff prior to providing confidential information (e.g., price) requested in the Third Set of Data Requests. We are reviewing the form of Protective Agreement proposed by Staff shortly after the rate application was filed and will provide comments or return it signed by the end of business tomorrow.

If you have any questions regarding this letter, please do not hesitate to contact the undersigned to discuss.

Very truly yours,

Michael A. Curtis
William P. Sullivan
For the Firm

WPS/maw
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UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.34: Please identify the number of hours MSB has expended to date in performing the following:

(a) Preparing data requests
(b) Reviewing responses to data requests
(c) Independently securing and reviewing information secured from sources other than MEC
(d) Preparing direct testimony

RESPONSE:

MSB does not record its hours in these particular categories. Rather it uses a functional description of the tasks performed. A major component not listed in the above categories is analysis which MSB performed in connection with reviewing responses to data requests, reviewing information from independent sources and drafting testimony.

In an effort to be responsive, Mr. Mendl reviewed his time records and estimated that he spent approximately 40 hours reviewing MEC's initial application and testimony filings and developing data requests. He spent approximately 80 hours reviewing responses to the data requests (some of this time also would have gone to analysis rather than review per se, and other of this time would have gone to developing follow-up and clarifying data requests). He spent approximately 15 hours securing and analyzing independent information. Mr. Mendl estimates that he spent approximately 70 hours preparing the testimony and exhibits, which includes analysis and writing/revision time. Mr. Mendl also estimates that he committed another 70 hours to analysis (which may have been pertinent to review of the responses to data responses, review of independent information, and preparing testimony) and other tasks. Note that these are only estimates as the time records do not permit direct assessment of the categories specified by MEC.

RESPONDENT: **Jerry E. Mendl, Consultant**

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.29: At page 27, line 15 of his direct testimony, Mr. Mendl states the $1.946 million (1%) prudence adjustment could be imposed "because MEC failed to maintain and provide the information to support the prudence of its purchased power." Please identify:

(a) The authority upon which Staff relies in proposing a prudence adjustment based on the inadequacy of the information maintained or provided.
(b) All ACC rules, decisions, orders or other controlling authority applicable to MEC that identified the purchase power information that MEC was expected to maintain in order to avoid a prudency adjustment.
(c) All Information that supports or contradicts Staff's position that MEC has failed to maintain required purchase power related information.
(d) All Information that supports or contradicts Staff's position that MEC has failed to produce purchase power related information requested by Staff.
(e) All ACC rules, decisions, orders or other controlling authority that indicates that MEC was required to provide information after objecting thereto, without an order compelling it to do so.

<u>RESPONSE</u>:

(a) Staff is in the process of compiling information and will supplement.

(b) Staff is in the process of compiling information and will supplement.

(c) Lack of supporting invoices (as specified in Mr. Mendl's direct testimony) that were not provided to the Commission as required by Decision No. 50266;

(d) See response to (c);

(e) Staff is in the process of compiling information and will supplement.

RESPONDENT: **Candrea Allen, Public Utilities Analyst II**

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.24: Please indicate whether and when Staff provided MSB with copies of MEC's monthly purchased power adjustor reports, including the date(s) the reports were provided, the time period covered by the reports and whether Staff attempted to include all information MEC had submitted to Staff in connection with the reports and provide any Information that supports or contradicts your response.

RESPONSE:

Once Staff received the signed protective agreement for MEC's monthly purchased power adjustor reports from MSB, Staff provided copies of the documents on September 2, 8, 12, and 13, 2011. Staff provided MSB copies of all monthly reports and invoices that were submitted from MEC between August 2001 and December 2010.

RESPONDENT: **Candrea Allen, Public Utilities Analyst II**

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.28: In connection with the \$1.946 million (1%) prudence adjustment being recommended by Staff (Recommendation 8 at page 47 of Mr. Mendl's Direct Testimony):

(a) Please identify all factors Staff considered, pro and con, that resulted in Staff recommending a \$1.946 million (1%) prudence adjustment.
(b) Please identify all other prudence adjustment levels considered by Staff.
(c) Please provide all correspondence, meeting notes, e-mails in which Mr. Mendl discussed the basis for an prudence adjustment with other non-legal ACC staff.
(d) Please identify any authority upon which Staff relied in developing its \$1.946 million (1%) prudence adjustment recommendation.

RESPONSE:

(a) Refer to Mr. Mendl's Confidential Direct Testimony, page 27.
(b) 0%, 5%, 10% and 100%.
(c) Please see the email from Mr. Mendl, attachment MWS 2.28

RESPONDENT: **Jerry E. Mendl, Consultant**

RESPONSE:

(d) Staff is in the process of compiling information and will supplement.

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.30: Is it Staff's position that MEC should pay a prudency penalty for sums paid to AEPCO, or others, at ACC approved rates for purchase of power? Please fully explain your answer.

RESPONSE:

No. If there were a verified quantity of energy purchased from AEPCO under approved rates, and if there were no other less costly power supplies from which MEC could have purchased power, the costs incurred to AEPCO would likely have been found prudent. However, MEC refused to provide the data necessary to document and verify the expenses for the 2001-2006 time period.

- MEC did not document the volumes allegedly purchased from AEPCO at the approved rates.
- MEC did not document that AEPCO was the cheapest source.
- MEC did not provide information regarding how much power was purchased from sources other than AEPCO from 2001-2006 after MEC gained that opportunity as a PRM. (For 2007-2010 where MEC provided data, power sources other than AEPCO represented 7-10% of total. Those sources are not under approved AEPCO tariffs. If approximately 8% of purchases in the 2001-2006 period were from sources other than AEPCO, the 1% adjustment is approximately one-eighth of non-AEPCO supplies by volume. However, the cost of non-AEPCO supplies may have been higher, as were the block purchases in 2007-2010. That would suggest that the 1% adjustment is less than one-eighth of non-AEPCO supplies by cost.)
- MEC did not document the cost of (or rates paid for) power from sources other than AEPCO.

RESPONDENT: **Jerry E. Mendl, Consultant**

Q:\Projects\Analytical\COS\AZ\MOHAVE\2010Retail Rates\Rebuttal Testimony\TIER.xls TIER.xls Sheet1 2/23/2012 9:02 AM

MOHAVE ELECTRIC COOPERATIVE, INC.

HISTORICAL TIER COVERAGES

	Actual			Staff Adj 2010	
	2009	2010	2011	w/rate chng CSB-3	w/rate chng & adj *
Operating TIER	0.32	0.19	(0.12)	1.57	0.15
RUS OTIER	0.52	0.30	(0.00)	1.68	0.26
Modified Net TIER	0.67	0.47	0.85	1.84	0.42
Net TIER	3.54	2.09	2.22	3.47	2.05

Note: By the time this adjustment is implemented, Mohave will no doubt have less "below the line" G&T patronage than in 2011, thus placing its net TIER at risk

RUS Required Coverages					
RUS OTIER	1.10	1.10	1.10	1.10	1.10
Net TIER	1.25	1.25	1.25	1.25	1.25

Operating TIER $\dfrac{\text{Operating Margins + Interest on LT Debt}}{\text{Interest on LT Debt}}$

RUS OTIER $\dfrac{\text{Operating Margins + Interest on LT Debt + Cash CC Refunds}}{\text{Interest on LT Debt}}$

Modified Net TIER $\dfrac{\text{Net Margins + Interest on LT Debt - G\&T Capital Credits}}{\text{Interest on LT Debt}}$

Net TIER $\dfrac{\text{Net Margins + Interest on LT Debt}}{\text{Interest on LT Debt}}$

* Staff "Prudency" Adjustment	(1,946,000)
* Staff 2010 and 2011 "Ineligible Power Cost" Adjustment	(1,124,070)
Total	(3,070,070)

	2009	2010	2011	w/rate chng CSB-3	w/rate chng & adj *
Interest on LT Debt	2,208,733	2,161,308	2,067,212	2,161,308	2,161,308
Operating Margin	(1,493,242)	(1,750,594)	(2,317,708)	1,229,404	(1,840,666)
Net Margin	5,619,827	2,355,173	2,513,414	5,335,171	2,265,101
G&T Capital Credits	6,340,428	3,509,969	2,820,502	3,509,969	3,509,969
Cash CC Refunds	441,272	243,588	243,588	243,588	243,588

Note: 2011 Form 7 is not finalized - Cash CC estimated at 2010 level

MOHAVE ELECTRIC COOPERATIVE, INC.

SHOWS THE EFFECT OF STAFF "PRUDENCY ADJUSTMENT" AND REFUND OF "INELIGIBLE COSTS"
APPLIED TO STAFF ADJUSTED
SUPPLEMENTAL DATA FOR THE YEAR ENDING DECEMBER 31, 2010

	Mohave Adjusted 12/31/2010	Staff Adjustments CSB-1	Staff Adjusted Test Year	Staff Recommended Change	Staff Recommended	Staff Penalty Adjustments	After Penalty
Operating Revenues	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1 Base Revenue (Remainder)	$ 36,732,893	$ 15,505,234	$ 72,238,127	$ 2,593,241	$ 74,831,368	$	$ 74,831,368
2 Base Revenue (TPS Pur Pwr)	3,222,980		3,222,980		3,222,980		3,222,980
3 PCA	15,505,234	(15,505,234)	0		0	(3,070,070)	(3,070,070)
4 Other	606,899		606,899	312,468	919,367		919,367
5 Total	$ 76,068,006	$ 0	$ 76,068,006	$ 2,905,709	$ 78,973,715	$ (3,070,070)	$ 75,903,645
6							
7 **Operating Expenses**							
8 Purchased Power	$ 61,802,677	$ (594,737)	$ 61,207,940	$	$ 61,207,940	$	$ 61,207,940
9 SubTransmission O&M	169,400		169,400		169,400		169,400
10 Distribution-Operations	2,773,698		2,773,698		2,773,698		2,773,698
11 Distribution-Maintenance	1,194,657		1,194,657		1,194,657		1,194,657
12 Consumer Accounting	2,227,246		2,227,246		2,227,246		2,227,246
13 Customer Service	196,226		196,226		196,226		196,226
14 Sales	96,252		96,252		96,252		96,252
15 Administrative & General	4,756,463	562,035	5,318,498		5,318,498		5,318,498
16 Depreciation	2,239,666		2,239,666		2,239,666		2,239,666
17 Tax	0		0		0		0
18 Total	$ 75,456,285	$ (32,702)	$ 75,423,583	$ 0	$ 75,423,583	$ 0	$ 75,423,585
19							
20 Return	$ 611,721	$ 32,702	$ 644,423	$ 2,905,709	$ 3,350,132	$ (3,070,070)	$ 480,062
21							
22 **Interest & Other Deductions**							
23 Interest L-T Debt	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308	$	$ 2,161,308
24 Amortize RUS Gain	0		0		0		0
25 Interest-Other	142,396		142,396		142,396		142,396
26 Other Deductions	17,024		17,024		17,024		17,024
27 Total	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728	$ 0	$ 2,320,728
28							
29 Operating Margin	$ (1,709,007)	$ 32,702	$ (1,676,305)	$ 2,905,709	$ 1,229,404	$ (3,070,070)	$ (1,840,666)
30							
31 **Non-Operating Margins**							
32 Interest Income	$ 410,049	$	$ 410,049	$	$ 410,049	$	$ 410,049
33 Gain(Loss) Equity Investments	110,369		110,369		110,369		110,369
34 Other Margins	(32,307)		(32,307)		(32,307)		(32,307)
35 G&T Capital Credits	3,509,969		3,509,969		3,509,969		3,509,969
36 Other Capital Credits	107,687		107,687		107,687		107,687
37 Total	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767	$ 0	$ 4,105,767
38							
39 Net Margins	$ 2,396,760	$ 32,702	$ 2,429,462	$ 2,905,709	$ 5,335,171	$ (3,070,070)	$ 2,265,101
40 Rate Change					3.820%		-4.036%
41 Operating TIER	0.21		0.22		1.57		0.15
42 RUS OTIER	0.23		0.24		1.58		0.16
43 OTIER (Modified Net TIER)	0.48		0.50		1.84		0.42

*** Staff Adjustment Consists of the following:**

"Prudency Adjustment" - Schedule Shown in Direct Testimony of Jerry Mendel, page 28, lines 4 - 9	$ (1,946,000)
"Ineligible Costs" - Expenses related to power supply - 2010	562,035
Estimated "Ineligible Costs" - Expenses related to power supply - 2011 & 2012	562,035
Total	$ (3,070,070)

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.32: Please describe how Staff's recommendations, if all except the $163,222 adjustment are adopted by the Commission, will impact the cash flow, TIER and DSC of MEC for the three (3) calendar years following the Commission entering a decision on MEC's rate application.

RESPONSE:

For Staff's calculation of cash flow, TIER, and DSC, there would be no impact as the $1.94 million amount would be recorded below-the-line.

However, the National Rural Utilities Cooperative Finance Corporation ("RUS"/"CFC") cash flow, TIER, and DSC calculations would be affected in the fiscal years in which any refunds are made to customers.

RESPONDENT: **Crystal S. Brown, Public Utilities Analyst V**

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01750A-11-0136

EXHIBIT
MEC-6

REJOINDER TESTIMONY OF

CARL N. STOVER, JR., P.E.

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

March 30, 2012

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REJOINDER TESTIMONY OF
CARL N. STOVER, JR., P.E.
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

SUMMARY OF REJOINDER TESTIMONY

Mr. Stover, is the Chairman of the Board of C.H. Guernsey & Company, Engineers · Architects · Consultants and files Rejoinder Testimony discussing the 18 recommendations included in Mr. Mendl's Surrebuttal Testimony. Mr. Stover discusses why Mohave Electric Cooperative supports, or at least does not contest, Recommendation Nos.:

1. Determining MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate [with the exception of his spot market qualifier].
8. Reducing MEC's purchased power bank balance by $91,537 for errors or omissions in calculating the purchased power cost and bank balance between August 2001 and December 2010, inclusive.
9. Determining that MEC's actual eligible purchased power costs were adequately documented from August 2001 and December 2010.
10. Determining that MEC's actual purchased power costs, adjusted to remove any ineligible costs and error or omissions [as ordered by the Commission], are prudent and reasonable for August 2001 through December 2010.
17. Acknowledging that MEC's selection and management of Western to provide critical services are prudent and reasonable.

Mr. Stover also discusses why the Commission should reject, in whole or in part Mr. Mendl's remaining recommendations.

REJOINDER TESTIMONY OF
CARL N. STOVER, JR., P.E.
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND YOUR EMPLOYER.

A. My name is Carl N. Stover, Jr., and I am employed by C. H. Guernsey & Company.

Q. ARE YOU THE SAME CARL N. STOVER, JR. WHO SUBMITTED DIRECT TESTIMONY AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted Direct Testimony and Rebuttal Testimony in this matter on behalf of Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative") in this proceeding.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. Surrebuttal Testimony was filed by Mr. Jerry Mendl, testifying on behalf of the Commission Staff, Utilities Division of the Arizona Corporation Commission. In his Surrebuttal Testimony, Mr. Mendl identified 18 recommendations to the Commission. The recommendations are based on the analysis presented in Staff's Direct Testimony as supplemented or modified in the Surrebuttal Testimony. My Rejoinder Testimony addresses these recommendations. Related recommendations have been grouped together by topic.

I. POWER SUPPLY PLANNING AND IMPLEMENTATION (RECOMMENDATIONS NOS. 1, 2, 3 AND 17)

Q. WHAT IS YOUR POSITION WITH REGARD TO MR. MENDL'S RECOMMENDATIONS NOS. 1, 2, 3 AND 17 RELATED TO THE REASONABLENESS OF MOHAVE'S POWER SUPPLY PLANNING AND IMPLEMENTATION FOR THE PERIOD 2001 THROUGH 2010?

A. Mohave, of course, agrees with the finding that "…MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate…." (Recommendation No. 1) Mohave also supports Mr. Mendl's acknowledgement "that MEC's selection and management of Western Area Power Administration ("Western") to provide critical services are prudent and reasonable." (Recommendation No. 17) Mohave disputes Mr. Mendl's conclusion that "it is inclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate." (Recommendation No. 3) The record is clear that Mohave implemented fundamentally the same power supply planning and implementation process as exists in 2010. In particular, Western and C. H. Guernsey have been retained throughout the entire period to provide critical services to Mohave in the power supply planning and implementation process. The only aspect missing was written documentation of the process. Given the amount of effort by both Mohave and Commission Staff, it would be a shame, and certainly not in the interest of any party, to create a cloud over the reasonableness of Mohave's power supply planning for periods prior to 2010 over the lack of written documentation outlining that process. I believe the analysis that has been conducted supports a finding that the power supply planning and implementation for the period prior to 2010 are reasonable and appropriate.

Q. WHY DO YOU BELIEVE THAT THIS FINDING IS SUPPORTED BY THE ANALYSIS DEVELOPED IN THIS PROCEEDING?

A. Based on my review of Mr. Mendl's analysis and at the risk of an oversimplification, I think the analysis involves three basic elements that need to be considered in arriving at a conclusion:

1. The first is whether or not the costs incurred were properly documented. In Recommendation No. 9, Mr. Mendl recommends that the Commission "…determine that the actual eligible power costs were adequately documented from August 2001 through December 2010."

2. The second is a determination of whether or not the implementation of the power supply plan resulted in costs that were prudent and reasonable. In Recommendation No. 10, Mr. Mendl recommends a finding that "…determined that MEC's actual purchased power cost, adjusted to remove

the ineligible costs and errors and omissions, are prudent and reasonable for August 2001 through December 2010." It is also important to note that after a second review of power costs for the period August 2001 to December 2006, Mr. Mendel determined "MEC's average purchased power costs excluding transmission compared favorably with market prices." (*see* page 7, line 4) In addition, if focusing on one transaction involving a block purchase in 2001, when asked if Mohave acted imprudently when purchasing the block power contract, Mr. Mendl answered "No." (*see* page 8, line 24)

3. The third involves having in place infrastructure, organization and policy/practices. Mr. Mendl discusses this beginning on page 5, line 26. Mohave has provided to Mr. Mendl an explanation of the infrastructure, organization and policy and practices in place from 2001 to present. Mohave has explained how all of these elements have evolved and changed over time. Mohave would be the first to admit that the documentation of the power supply strategy and implementation in place today was not in place in 2001, but the same basic structure reflected in today's documentation was put in place in 2001. Unfortunately, after reviewing the information provided Mr. Mendl comes to the conclusion "....it is inconclusive whether MEC's policies of power supply planning and implementation prior to 2010 are reasonable and appropriate." (Mendl Surrebuttal at page 6, line 3)

In dealing with the third issue, I would like to point out two things. First, in dealing with organization, Mohave has had essentially the same team in place. Western has been a part of the team since inception. In fact, Mr. Mendl's Recommendation No. 17 again supports a finding that Western's involvement has been prudent and reasonable. A critical consideration is that the activities of the team in place and the process and procedures implemented have resulted in power costs that Mr. Mendl has found reasonable. Therefore, Mohave believes there is support in this docket for a finding that Mohave's power supply planning and implementation for the period prior to 2010 was reasonable and appropriate and that there is a basis for the Commission to conclude that power supply planning and implementation prior to 2010 were reasonable and appropriate.

Q. **ARE THERE ANY OTHER CONSIDERATIONS THAT WOULD SUPPORT A FINDING ON THIS ISSUE?**

A. Yes. Based on Mr. Mendl's comment that for the period August 2001 to December 2006 "...MEC's average purchased power costs excluding transmission compared favorably with market prices." (page 7, line 4) and when he focuses on one transaction that he questions dealing with a block purchase and after review of that transactions comes to the conclusion "... I cannot conclude that MEC acted imprudently in obtaining that power given the nature of the market prices ....." (page 8, line 25), it seems to me there is ample support for the Commission Staff for a finding that supports a finding that Mohave's power supply planning and implementation was prudent and in the interest of the Member consumers.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE QUALIFIER IN RECOMMENDATION NO. 1, MORE FULLY EXPLAINED IN RECOMMENDATION NO. 2 RELATING TO MOHAVE'S LIMIT ON SPOT MARKET POWER PURCHASES?

Yes. I believe Mr. Mendl still fails to fully appreciate the nature and purpose of the 10% limit criterion Mohave uses in relation to spot market purchases. There simply is no reason for the Commission to interject itself in Mohave's spot market purchase process or to "...direct MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on the MEC resource planners."

In Section 5 of his testimony (beginning page 21), Mr. Mendl has a number of comments referencing this issue. My understanding is that he sees no distinction between a policy and a criterion ("that distinction is a red herring," page 21, line 9). He also believes that the reference to spot market purchases is related to capacity planning and not energy purchases ("However, the criterion in question is for capacity planning, not for economy energy as Mr. Stover suggests" (page 21, line 22), "Mr. Stover obfuscates the point by mixing the capacity planning criterion with economy energy dispatch," (page 22, line 21)).

I think it would be helpful to clarify Mohave's position and to identify any real differences between the position of Staff and Mohave, if any.

Q. PLEASE EXPLAIN MOHAVE'S POSITION RELATING TO THE ROLE OF THE 10% CRITERION RELATED TO MOHAVE'S SPOT MARKET POWER PURCHASES.

A. Mohave outlined general concepts related to power supply planning and procurement (*reference* Exhibit JEM-2, page 6). The statement references "criteria" for determining power supply decisions related to block purchases. From Mohave's perspective, making reference to a criterion as compared to a policy reflects considerably greater flexibility to react and adjust to changing conditions. The 10% criterion acts as a safeguard that requires internal discussions with management when the limit is approached. It does not create a fixed goal or absolute limit on the amount of Mohave's block purchases. Further, it reflects a point of reference that the Board expects management to provide a specific rationale for exceeding the 10% threshold. It does not preclude management from acting if deemed appropriate to take "full advantage" of lower costs on the spot market. Mohave believes the 10% criteria is fully consistent with Mr. Mendl's suggestion that there needs to be flexibility in reacting to changing conditions and that it is <u>not</u> appropriate to have a fixed percentage value in establishing a particular element of a power supply plan (e.g., market exposure).

Mr. Mendl also indicates that the criterion in question is applied to capacity planning and not energy. Each year when developing the summer power supply strategy and determining the amount of block purchases it intends to acquire, Mohave is considering the amount of energy and not the amount of capacity that will be exposed to market. The 10% criterion as used by Mohave and Western is a metric related to energy and not capacity. Capacity is certainly a consideration; however, we tend to focus on capacity resources more in the long-range planning activity. Any suggestion that the market exposure criterion applies only to capacity related decisions, is incorrect.

Mohave has responsibility for developing and implementing a power supply strategy and plan. Mohave objects to any suggestion that the Commission should become involved in directing or prescribing any specific planning or implantation activity. Mohave recognizes that, at the end of the day, it may be required to demonstrate that it has made prudent decisions that are in the best interest of its Member consumers. I believe that Mohave has functioned in a manner that is in the best interest of its Member consumers since it assumed the power supply planning function.

II. DOCUMENTATION AND PRUDENCY OF PURCHASED POWER COSTS (RECOMMENDATION NOS. 9 AND 10)

Q. WHAT IS MOHAVE'S POSITION WITH REGARD TO RECOMMENDATION NOS. 9 AND 10?

A. Mohave supports determinations that the actual eligible purchased power costs for the period August 2001 through December 2010 were adequately documented and, adjusted to remove any ineligible costs and errors or omissions the Commission determines to exist, were prudent and reasonable. I believe these findings are fully supported by the record. Mohave appreciates the detailed work that Mr. Mendl did to arrive at this conclusion. As I indicated previously, I also believe these findings support a conclusion that MEC's power supply planning and implementation policies for the entire period were reasonable and prudent.

III. PURCHASED POWER RELATED CONSULTING, LEGAL AND STAFF EXPENSE (RECOMMENDATION NOS. 4, 5, 6, 7 AND 12)

Q. WHAT IS THE NATURE OF RECOMMENDATION NUMBERS 4, 5, 6, 7 AND 12?

A. These recommendations involve Mohave's inclusion of $594,737 in power supply-related consultant, legal, lobbying and staff costs as a part of its PPCA in 2010. Mr. Mendl characterizes the costs as "ineligible costs" and recommends $562,035 be allocated to revenue requirements for the general rates and all $594,737 be removed from the PPCA bank balance as soon as practicable. He further recommends that when the Commission conducts its next prudency review an adjustment be made at that time to remove any similar costs contained in the PPCA bank balance. Mohave does not contest the removal of $32,702 in lobbying-related expense (even though related to power supply procurement). Therefore, the amount at issue is the $562,035 of 2010 purchased power related consultant, legal and staff costs included in the PPCA bank balance.

Q. WHAT IS THE NATURE OF THE ISSUE BEFORE THE COMMISSION?

A. It is important to point out that the Commission Staff has concluded that these costs are reasonable and should be recovered. The only issue is how the costs should be recovered. Mohave is proposing the costs be recovered through the power cost adjustor commencing with 2010, whereas Commission Staff is recommending that the costs be recovered in base rates as of the effective date of new rates. As I explained in my Rebuttal Testimony, an alternative position is to allow the costs to be recovered through the power cost adjustor until such time as the costs are recovered in base rates. This would mean that Mohave would continue to flow through the power supply-related costs as part of the real power cost adjustor until the rates determined in this proceeding go into effect.

Q. WHY DO YOU BELIEVE THAT MR. MENDL'S RECOMMENDATION SHOULD BE REJECTED?

A. Mr. Mendl identified two criteria in his direct testimony for inclusion in the PPCA which I addressed in my Rebuttal Testimony. Mr. Mendl is now proposing a third criterion based on a concept of double recovery of costs. More specifically, Mr. Mendl states, "When MEC talks about recovering these ineligible costs through the PPCA, what it is really doing is doubling up on its recovery, since from August 2001 through December 2009 (at least) these costs were being recovered exclusively through the general rates." (*see* page 16, line 16)

Q. HAS MR. MENDL OFFERED A RECOMMENDATION AS TO HOW HE WOULD HAVE PREVENTED A DOUBLE RECOVERY?

A. Yes. In responding to a question about the reasonableness of recovery of the cost at issue, Mr. Mendl states that, "I would agree if MEC had reduced its general rates when it segregated out the ineligible costs for inclusion of the PPCA. But it did not." (*see* page 17, line 7)

Q. DO YOU AGREE WITH MR. MENDL'S CONCERN ABOUT DOUBLE RECOVERY OF COSTS?

A. There should not be a double recovery of costs and Mohave is not seeking one here. Mohave's current rates went into effect for all billings on and after January 1, 1991 and are based upon a test year ending July 31, 1989. There is no way that its general rates include the expenses associated with purchased power planning and acquisition activities that did not commence until Mohave became a partial requirements customer in 2001 (ten years after the rates became effective). Since these costs are not recovered by existing rates, Mohave did not need to reduce its general rates by the amount of costs included in the PPCA to avoid double recovery.

Q. DOES THE FACT THAT MOHAVE DID NOT BEGIN RECOVERY OF THESE COSTS THROUGH THE PPCA UNTIL 2010 PROVIDE A BASIS TO DISALLOW RECOVERY THROUGH THE PPCA?

A. No. Mohave should not be penalized for absorbing these costs for almost a decade before including them in the PPCA. I explained the reasons for the delay at page 19 of my Rebuttal Testimony, including the need to implement procedures to separately document and book these purchased power related costs sufficiently to allow them to be included in the monthly PPCA bank balance filings made with the Commission, as well as the availability of margins from third-party sales to support these activities.

Q. WHAT IS YOUR PERSPECTIVE ON MR. MENDL'S CONTENTION AT PAGE 16 OF HIS SURREBUTAL TESTIMONY THAT MOHAVE USED THE PPCA TO DEVELOP A NEW REVENUE STREAM WITHOUT COMMISSION AUTHORITY?

A. Mr. Mendl's assertion is based on Mr. Carlson's factual statement "that had these costs not been collected through the PPCA, Mohave's financial performance would have been adversely affected." (Carlson Rebuttal, page 13, line 2) The reality is Mohave merely started to recover previously unrecovered purchased power related expenses through its duly authorized PPCA. Mr. Mendl cites to no Commission rule or order that applies to Mohave that excludes these expenses, if properly documented, from the PPCA.

Q. Mr. Mendl references Commission Decision No. 68071 and an excerpt from Ms. Keene's prefiled Direct Testimony to support his assertion that the Commission has already determined what costs could be included in a cooperative's PPCA (Surrebuttal at page 14, line 15). What is your perspective on Mr. Mendl's position?

A. The matter referenced by Mr. Mendl involved AEPCO, which, as Mr. Mendl recognizes is a generation cooperative, not a distribution cooperative like Mohave. I have also reviewed the Decision cited by Mr. Mendl. While the Commission certainly authorized AEPCO to "amend its tariffs to include a Fuel and Purchased Power Cost Adjustor as described herein" (Decision No. 68071 at page 16, line 14) nowhere does the Commission expressly set forth what costs could or could not be included in the FPPCA. Additionally, since Staff and AEPCO agreed to the accounts as outlined in Ms. Keene's testimony (Decision 68071 at page 6, line 4), there was no issue before the Commission regarding whether any other purchased power related accounts, such as costs booked to Account 557 (Other Expenses), could be included in the PPCA. Staff also recognized that the revenues from certain sales for resale should be reduced by "legal expenses" before being credited against the cost component. This effectively reduced the credit and increased the bank balance as a result of legal expenses. In fact, Staff only expressly recommended exclusion of legal fees in connection with Account 501, which Mr. Mendl acknowledges would not apply to Mohave. (Mendl Surrebuttal, page 15, line 21) While not an attorney, this Decision does appear to establish whether Mohave's 2010, prudently incurred, power supply-related consulting, legal and staff expenses were or were not includable in Mohave's PPCA.

Q. YOU MADE REFERENCE TO COSTS BOOKED TO ACCOUNT 557. IS THIS ACCOUNT LISTED AS A PART OF OTHER POWER SUPPLY EXPENSES?

A. Yes. Mohave booked the 2010 costs at issue to Account 557 because they are associated with purchased or power supply related activities. Mohave started identifying and separately booking these costs in 2008, but had not refined their documentation sufficiently to include them in the PPCA until 2010.

Q. HAS THIS ACCOUNTING FOR COST BEEN APPROVED BY MOHAVE'S AUDITOR?

A. Yes.

Q. ARE THESE PRUDENTLY INCURRED COSTS?

A. Yes. Staff has agreed $562,035 of the costs booked to Account 557 can be recovered from the retail member consumers served by Mohave.

Q. DOES STAFF AGREE THAT COSTS PRUDENTLY INCURRED MAY BE INCLUDED IN AN ADJUSTOR?

A. Yes. Reference Mr. Mendl's testimony, page 15, line 8, where Mr. Mendl quotes testimony of Barbara Keene in which she states "The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included". It seems to me that Ms. Keene is recognizing that a cost does not have to be related directly to the purchase of a kW of capacity, the purchase or a kWh of energy, or consumption of a MMBtu to qualify.

Q. DO YOU AGREE WITH MR. MENDL'S RECOMMENDATION 12 THAT 2011 AND 2012 CONSULTANT, LEGAL, LOBBYING AND IN-HOUSE LABOR COSTS RELATED TO POWER SUPPLY PLANNING AND PROCUREMENT BE EVALUATED AND REMOVED FROM THE BANK BALANCE AT THE TIME OF THE NEXT PRUDENCE REVIEW?

A. For the reasons already explained, I do not agree that such costs should be removed from the PPCA. However, to the extent the Commission agrees with Staff and precludes past, present and future recovery of these costs through the PPCA, then I agree that it would be appropriate to evaluate and deal with these expenses, with all other 2011 and 2012 expenses and credits, in the next prudence review of Mohave's power purchases.

IV. ERRORS AND OMISSIONS IN PPCA CALCULATIONS (RECOMMENDATION NO. 8)

Q. IN RECOMMENDATION NO. 8, Mr. MENDL RECOMMENDS THAT $91,537 BE ADJUSTED IN THE PURCHASED POWER BANK BALANCE DUE TO ERRORS AND OMISSIONS IN CALCULATING THE PURCHASED POWER COST FROM AUGUST 2001 TO DECEMBER 2010. DO YOU AGREE?

A. Mohave does not contest Mr. Mendl's proposed adjustment of $91,537.

V. RATE CASE FILING AND STREAMLINING (RECOMMENDATION NOS. 11 AND 14)

Q. DO YOU AGREE WITH THE RECOMMENDATION THAT THE COMMISSION REQUIRE MOHAVE TO FILE A RATE CASE NO LATER THAN 9/1/2016?

A. While Mohave appreciates the short delay in the filing requirement to September, it still opposes the Commission requiring a full rate case by a date certain in the future in order to make certain "...purchased power cost data and supporting information remain fresh." (Recommendation No. 11). The timing for the next rate case is a management decision best left to the Mohave Board to make based on conditions specific to Mohave. A rate case is expensive and an exhausting effort for a cooperative, and in particular a smaller cooperative like Mohave. To require a rate case in order to have fresh power cost data should not be a primary consideration.

Q. IF THE CONCERN IS THE PRUDENCY OF POWER SUPPLY PLANNING AND IMPLEMENTATION, WHAT ALTERNATIVE WOULD YOU SUGGEST?

A. Recommendation No. 13 deals with files and records that Mohave will maintain and provide to the Commission for review of power supply issues. The Commission will have the data required to determine if Mohave is properly executing its power supply planning and implementation strategy. The Commission at any time could perform a review and does not have to wait for the next rate case.

Q. SHOULD MEC AND STAFF BE REQUIRED BY THE COMMISSION TO MEET WITHIN TWO MONTHS OF A DECISION IN THIS CASE TO DISCUSS OPTIONS FOR STREAMLINING THE RATE CASE PROCESS AND IDENTIFY ISSUES AND INFORMATION FOR THE NEXT CASE?

A. Such a requirement is unnecessary. First, Staff has always been open to informal discussions regarding ways to process rate cases more efficiently, as well as to pre-filing discussions regarding what issues and information will be involved in an upcoming rate case. Secondly, I understand the Commission has opened a separate rulemaking docket (ACC-00000B-11-0308) to evaluate methods to streamline cooperative rate cases. That proceeding should be allowed to run its course.

VI. ON-GOING RECORDKEEPING (RECOMMENDATION NO. 13)

Q. DO YOU AGREE WITH RECOMMENDATION NO. 13 DEALING WITH THE REQUIREMENT THAT MOHAVE MAINTAIN ALL FILES AND RECORDS PERTINENT TO THEIR PURCHASED POWER PLANNING AND PROCUREMENT?

A. I do not think Recommendation 13, as worded, is in anyone's best interest. What Mohave supports is clarity between Mohave and Staff regarding exactly what documentation Mohave is expected to maintain to facilitate the prudency review process. To facilitate that understanding, Mohave believes meetings should be held with Staff to further discuss their expectations. I recommend the discussions begin with Staff response to Mohave's RFI MWS-2.14 which asked specifically what data is required to support the purchased power cost adjustor. This would go to the issue of maintaining the proper data base for review of purchased power activities. Mohave Rejoinder Exhibit CNS-1 is a copy of that response. My recommendation is that Staff and Mohave work with this response in formulating a more precise statement of what Mohave will need to provide and what the Staff will need to review in order to monitor the prudency issue. A blanket requirement of the type set forth in Recommendation 13 is inappropriate and should be rejected. An alternative is to require Mohave and Staff meet to develop a listing of the types of documentation Mohave will maintain.

VII. TREATMENT OF THIRD-PARTY SALES (RECOMMENDATIONS NO. 15 AND NO. 16)

Q. WHAT IS YOUR POSITION WITH REGARD TO TREATMENT OF THIRD-PARTY SALES IN PPCA?

A. The issue is whether or not the margins associated with third-party sales (TPS) should be included or excluded in determining the PPCA bank balance. I think Mr. Mendl accurately contrasted the differences in the two approaches. Mohave is proposing to credit to the PPCA calculation the cost of making the TPS, and the Staff is proposing to credit to the PPCA calculation the total revenue associated with the TPS. The difference is that under the Mohave approach the margins associated with the TPS flow to margins on the income statement, the margins increase the coverage ratios (TIER and DSC), the margins flow to the balance sheet to increase equity and the cash position on the balance sheet, the margins are allocated to the Member consumers, and the margins will eventually be paid to the Members as capital credits.

With the Staff method the magnitude of the PPCA is reduced, which in turn reduces the current rates paid by the Member consumer served by Mohave.

The Member consumer benefits with both methods, however, the manner in which the benefits are realized are different. Under the Staff method the Member sees an immediate decrease in power cost but there is no benefit to margins or equity. The Member does see a benefit in increased patronage capital however, that benefit will not be paid to the Member until some future period.

Q. ARE THERE OTHER FACTORS TO CONSIDER IN EVALUATING THIS ISSUE?

A. One of the justifications I raised in rebuttal testimony for not crediting margins in the PPCA calculation is that margins are typically earned during non-peak months, and if there is a credit to PPCA for margins earned the benefits would not flow to customers with usage during the peak months. Mr. Mendl suggests using the PPCA bank as a buffer to reallocate the distribution of benefits associated with the margins. He is correct, and Mohave can certainly do that. In fact, given this solution Mohave can use the PPCA bank to reallocate any number of cost causation relationships to different customer groups at different times of the year. The question is whether this reflects a more equitable solution and reflects better policy than an approach in which margins are allocated to the Member consumers based on patronage capital.

VIII. AEPCO'S MARGINAL COSTS (RECOMMENDATION NO. 18)

Q. WHAT IS YOUR POSITION WITH REGARD TO THE RECOMMENDATION THAT MOHAVE REQUEST INFORMATION REGARDING AEPCO'S MARGINAL OPERATING COST?

A. Recommendation 18 is unnecessary. Mohave is continuing to work with AEPCO to improve the relationship between rates charged by AEPCO and costs incurred by AEPCO in providing service to Mohave. A major step was the unbundling of base and peaking resources in the last AEPCO rate case. Mohave would like to have access to AEPCO's marginal operating costs, but understands why AEPCO would be hesitant to provide such information for legitimate business reasons. To the extent AEPCO rates reflect current costs or AEPCO otherwise shares current marginal cost information, Mohave will be able to make better regional power dispatch decisions. Mohave has been working with AEPCO and will continue to work with AEPCO to improve the process. The point being that the Commission does not have to order something that is already occurring.

IX. BASE PURCHASED POWER COST (RECOMMENDATION NO. 19)

Q. WHAT IS YOUR POSITION WITH REGARD TO THE BASE PURCHASED POWER COST RECOMMENDED BY MR. MENDL?

A. Mr. Searcy addresses this recommendation in this testimony.

X. OTHER ISSUES

Q. ARE THERE ANY OTHER ISSUES IN MR. MENDL'S TESTIMONY THAT YOU WISH TO ADDRESS?

A. Yes. In rebuttal testimony I commented on how Staff's adjustments would impact Mohave's financials. I was addressing the Staff position that its proposed prudence adjustment and removal of purchased power related consulting, legal and staff costs would not impact Mohave's cash flow, TIER and DSC. Staff's assertion was wrong. There will be an impact on the financials. On page 25 starting at line 17 of his Surrebuttal, Mr. Mendl points out that the impact on Mohave's financials will be reduced now that Staff has dropped its recommended adjustments from $3.1 million to $0.7 million (by totally eliminating its proposed $1.94 million dollar prudency adjustment and deferring any PPCA for 2011 and 2012 expenditures until the next prudency review). I agree that the adverse impact will be reduced substantially, but certainly not eliminated.

Mr. Mendl also commented (page 26, beginning line 12) on a statement made by Mr. Carlson related to when rate increases are sought and then Mr. Mendl goes on to discuss fluctuations in the PPCA rate and bank balance. I want to make sure there is an understanding of the needs for rate adjustments vs. the fluctuations in the PPCA rate and bank. As pointed out by Mr. Carlson, one of the factors driving a need for a rate change is the financials. (Carlson Rebuttal at page 5, line 31) The financials reflect accrual accounting and assume a full recovery of any amount of PPCA due to be collected whether or not it is collected. Changes in the PPCA bank reflect the cash position of the Cooperative but not the accrual position. Therefore, fluctuations in the PPCA factors or bank balance are not an indicator of Mohave's intent related to maintaining adequate income statement objectives.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes, it does.

**UTILITIES DIVISION STAFF'S RESPONSES TO
MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET
OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION
DOCKET NO. E-01750A-11-0136
FEBRUARY 17, 2012**

MWS-2.14: Please set forth all data (by category or type) the Commission Staff now expects MEC to maintain to support purchased power costs recovered through its purchase power adjustor.

RESPONSE:

MEC would continue to file its monthly purchased power adjustor report including the following information:

- A cover letter that:
  - Is addressed to the Commission's Compliance Section;
  - The month for which the monthly report is being filed;
  - The Decision No(s). which ordered the monthly report and/or information required to be included; and
  - The name and contact information of the employee who can be contacted regarding the information provided in the report.

- Bank Balance Report for the month indicated in the cover letter including:
  - The beginning bank balance which should equal the previous month's ending bank balance. (Any revisions to the ending or beginning bank balance of a particular month should be reflected in the previous month's or succeeding month's bank balance report.);
  - Jurisdictional kWh sales by customer class;
  - Actual cost of purchased power (including transmission costs) supported by invoices. Copies of all invoices for power purchased and transmission should be included. (Invoices for costs for services other than purchased power that MEC intends to recover through the purchase power adjustor.);
  - Unit cost of purchased power;
  - Authorized base cost of purchased power;
  - Authorized purchase power adjustor rate;
  - Incremental difference between the actual and the authorized cost of purchased power;
  - Net changes to the bank balance;
  - Adjustments to the bank balance. (Any and all adjustments to the bank balance should be documented as a sub-report to the Bank Balance Report which should include a detailed explanation of any adjustments and the itemized amounts including the total amount of the adjustment(s). This sub-report should be titled *Adjustments to Bank Balance* and should specify the month for which the adjustment(s) are being made.); and

    - Ending bank balance which should be the sum of the beginning bank balance, net changes to the bank balance, and adjustments to the bank balance.

- Revised monthly purchased power adjustor reports:
    - Should MEC find it necessary to file revised monthly reports, the cover letter of the revised filing should clearly state that the filing is a revised version of the previously filed report. In addition, the cover letter should indicate what information is being revised. Further, the revised information should be distinguished from the information not revised (e.g. highlight, different font, bolding, etc). The revised report should be filed in the same manner as the original report.

Because legal fees, consulting fees, lobbying fees, DSM costs or any other fees/charges/costs not approved to be recovered through the purchased power adjustor, invoices for these activities should not be included in the monthly purchased power adjustor reports.

RESPONDENT: Candrea Allen, Public Utilities Analyst II

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01750A-11-0136

EXHIBIT
MEC-7

REBUTTAL TESTIMONY OF

J. TYLER CARLSON

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

February 24, 2012

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REBUTTAL TESTIMONY OF
J. TYLER CARLSON
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

SUMMARY OF REBUTTAL TESTIMONY

Mr. Carlson is the Chief Executive Officer of Mohave Electric Cooperative, Incorporated. In his rebuttal testimony Mr. Carlson discusses the fundamental differences between an electric distribution cooperative and an investor owned electric utility. As the elected representatives of the member-customer owners, a cooperative's Board of Directors is in a strong position to balance the needs of the Cooperative and the customers. In reality, the needs of the cooperative and its member-customers do not compete as both seek reliable energy at the lowest practicable cost consistent with prudent utility management.

Mr. Carlson discusses the members' desire to have prepaid service implemented immediately and explains why pursuit of prepaid service in a separate docket, as recommended by Staff, is contrary to the needs of Mohave's customers.

Additionally, Mr. Carlson discusses:

1) Customer support for the residential customer charge proposed by Mohave;

2) The inappropriate rate design Staff proposes for large commercial and industrial time of use customers;

3) The unjustified $1.946 million prudency penalty recommended by Staff;

4) Staff's erroneous recommendation to adjust Mohave's PPCA bank balance an additional $594,737.45+;

5) Detrimental impacts flowing from the change Staff recommends third party sales be booked; and

6) Staff's unnecessary recommendation that the Commission mandate the timing and test year for Mohave's next rate filing.

Mr. Carlson concludes his rebuttal testimony by requesting the Commission expeditiously implement a streamlined rate making process for electric distribution cooperatives to avoid the unnecessary time and costs involved in the current ratemaking process.

1. INTRODUCTION

Q. Please state your name, your employer and your position.

A. My name is J. Tyler Carlson. I am the Chief Executive Officer of Mohave Electric Cooperative, Incorporated ("Mohave" or "Cooperative") and have served in that capacity since March of 2010.

Q. Please briefly describe your background.

A. I have a degree in electrical engineering and a PE. I started at Mohave in 2008 as the Chief Operating Officer, with primary responsibility for Engineering, Operations and Power Supply. From 1993 to 2008, I was the Regional Manager for the Western Area Power Administration. My responsibilities included power system operations, transmission operations, power marketing, rates and repayment, contracts and all other functions of a public power entity. I was also a Division Director for System Protection at an investor owned utility and began my career at a small distribution cooperative in Minnesota.

2. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides Mohave's management's perspective on the following issues:

1. The fundamental differences between member owned electric cooperatives and for profit electric utilities.
2. The need for expedient implementation of a prepaid service option.
3. The need to, and customer support for recovering a greater portion of the base cost of providing service through the customer charge.
4. The unjustified, unfair, unjust and unreasonable 1.94 million dollar prudence penalty related to Mohave's power purchase practices Staff is recommending.
5. The unnecessary and inappropriate power purchase bank adjustment Staff recommends relating to purchase power related legal, consulting and staff costs collected since 2010 under its power purchase clause adjustor (PPCA).

6. Why third party sales should remain outside the PPCA.
7. Why Mohave should not be ordered to make another rate filing in 2016.
8. The need to significantly streamline the current ratemaking process for cooperatives.

3. COOPERATIVE VS. IOU

Q. Would you discuss some of the fundamental differences between member owned electric cooperatives and investor owned electric utilities?

A. Two fundamental distinctions between an electric cooperative and an investor owned cooperative are their form of ownership and the resulting fiduciary duties of their Boards of Directors. An IOU is owned by shareholders who have invested in the utility to make a return or profit. As a result, the Board of Directors and management of an IOU have a fiduciary duty to operate the utility to provide a return for its shareholders. Securing a reasonable return for their investors is a fundamental aspect of their business.

In contrast, a cooperative is formed and owned by the customers its serves. The primary purpose of the cooperative is to secure and distribute electricity reliably and at a price that is consistent with good business practices and is fair and equitable to its member-customers. A cooperative is incented to provide reliable service while minimizing costs to its members regardless of regulatory oversight. Members understand that positive margins will be retained by the cooperative for 15 to 25 years before being returned to members without interest, or, if distributed early due to death of the member, at a discount.

Additionally, while an IOU's board of directors is elected by its shareholders, most of whom are not its customers, a cooperative's board of directors is elected from and by the customers the cooperative serves. Each Mohave director represents a specific district and is elected by the customers of that district. In other words, in contrast to directors of an IOU – or even Commissioners elected in 'statewide' elections - the directors of a cooperative are the elected representatives of the very customers served by the cooperative. A cooperative's board of directors has no incentive or desire to increase its rates and charges, especially for its rank and file members – the residential customers. Increases are sought only when they are necessary to continue to provide reliable electric service, both in the short term and the long term, and/or in order to satisfy financial criteria established by their lenders.

Q. Are there also differences in the character of the service area and customer base of an IOU and a cooperative?

A. Yes. Most cooperatives were formed where IOUs were unwilling or at least reluctant to serve because the lack of density or load profile would not provide the IOU sufficient returns to satisfy their shareholders. The service areas of cooperatives are therefore predominately rural and with lower overall densities than those of IOUs.

Q. Should the Commission consider the Cooperative as an entity separate and distinct from the customers they serve?

A. Whereas the shareholders of an IOU and the corporation they formed may be seen as separate and distinct from the customers they serve, such is not the case with cooperatives. The cooperative's owners and customers are one and the same.

Q. Should the Commission treat the request of a cooperative's board differently than it treats the request of an IOU?

A. The fundamental distinctions between the two types of utilities, the fact that a cooperative's board is directly elected by the customers it serves and the members of its board are both directly impacted and representatives of the very customers their requests for action will affect collectively warrant the Commission giving greater weight and deference to requests of a cooperative than given to the requests of an IOU.

When a cooperative's board requests a rate increase, revised rate designs or initiation of a new service, they too will experience the impacts of the changes and will be subject to the will of the members if their member-customers' concerns have not been adequately considered and addressed. To my knowledge, not a single member of Staff or the Commission will be directly impacted by the rates that will be put into effect at the end of this proceeding.

During the entire process of developing this requested rate increase, the Mohave Board carefully deliberated, reached out to its customers in town halls and acted to minimize both the overall increase and the adverse impacts on any particular class of customer. No rate consultant was hired before the Mohave Board was convinced a rate increase was necessary. As a result the feedback from customers has been positive. At the town halls, which I personally attended, everyone expressed support and agreed that two of the most important elements of this rate application were 1) securing a customer charge that recovered the basic costs of providing service and 2) implementing prepaid metering service.

A cooperative's board, or at least Mohave's Board, has a much greater relationship with its customers and is more directly impacted by their own decision to raise rates than shareholders or members of the board of an IOU, or even Staff and the Commissioners. Given all these factors, the requests of Mohave's Board should not be rejected without a strong evidentiary basis demonstrated on the record. And while the Cooperative's Board and I respect the Commission Staff, it is clear that they have not demonstrated that the Mohave's Board's requests should be rejected on any of the issues that remain in this matter.

4. PREPAID SERVICE

Q. Why is Mohave proposing prepaid service?

A. Mohave's members are anxious for prepaid service to be implemented. Prepaid service is a way to secure electric service without putting down a deposit equivalent to 2 months of billing, having a good credit history or being a customer in good standing for 12 months. It provides customers the opportunity to pay as they go rather than in 30 day increments. It affords customers the opportunity to forego electricity for a day or two without incurring a minimum monthly bill and paying reconnection fees. These aspects of prepaid service will always be meaningful to customers in our service area, but are even more so while they are suffering from a depressed economy. Prepaid service is not being forced on Mohave's members. It is a service they are requesting and a service Mohave wants to provide.

Q. What is the prepaid service concept that Mohave has proposed?

A. As part of our rate application that was filed almost a year ago now, on March 30, 2011, we filed updated and revised Service Rules and Regulations that added Prepaid Service under Section 102-I as an alternative to posting a deposit. A copy of the new Section 102-I is attached to my testimony as JTC-Rebuttal Exhibit 1. We have also developed a Prepaid Service Agreement which is attached as JTC- Rebuttal Exhibit 2.

Q. Is Staff supporting or opposing Mohave's concept for prepaid service?

A. Mohave understands that Staff does not oppose the concept of prepaid service, but to date Staff has opposed prepaid service as an energy efficiency program. Mohave is not proposing prepaid service as an energy efficiency measure, but as an alternative to deposit requirements. Staff had more than 9 months between the filing of our application and the filing of its direct testimony to investigate and evaluate Mohave's proposal. All data requests and responses related to the proposal are attached as JTC-Rebuttal Exhibit 3. Yet, Staff witness Candrea Allen testified "If Mohave wishes to pursue a pre-pay option, Staff recommends that Mohave file, in a separate docket, an application for Commission approval of prepaid metering." Direct testimony of Candrea Allen, p. 5, lines 15-17.

Q. Does Mohave support Staff's recommendation?

A. No. We filed our proposal almost a year ago. There is no reason this service should not be approved with the rest of Mohave's Service Rules and Regulations as part of this docket.

Q. Ms. Allen at page 5, lines 9-10 also suggests Mohave engage in discussions with stakeholders and other interested parties to further evaluate and assess its proposal. Does Mohave believe such action is necessary or appropriate?

A. As I indicated earlier, we have already received significant input from our customers. It is our customers requesting the prepaid service. We believe Section 102-I adequately explains the prepaid service program and does so in a fair and equitable manner. We are willing to consider specific recommendations of Staff, but the suggestion that it be handled in a separate docket is unacceptable to Mohave, unless Staff can ensure Mohave that such application would be approved before a decision is rendered in this matter.

Q. At page 5, lines 4-5, Ms. Allen indicates Mohave did not provide any analysis relating to the implementation of prepaid metering. Do you know to what she is referring?

A. It is unclear as to the type of analysis to which Staff refers. Since the service is totally optional, and a customer can leave at any time, Mohave does not understand what type of additional analysis is required or would be beneficial. Staff had over 9 months to request any specific analysis it deemed was necessary, but did not do so. There is a desire and need for prepaid service now. Awaiting an unspecified analysis is unnecessary and does not support Staff's recommendation that prepaid service be addressed in a separate docket.

Q. Do you have any comment on Ms. Allen's suggestion that Mohave would benefit from modeling its proposal after the Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC") application for its Experimental Pre-Paid Residential Tariff (docket E-01575A-11-0439)?

A. We have closely examined SSVEC's application which was filed 8 months <u>after</u> we submitted our proposal. We have concluded that there are few substantive differences between the two proposals other than proposing the service as a tariff versus through a rule. Since the rate for customers using prepaid service is the same as that of a standard residential service, pro rata to the number of days of use, we do not believe a separate tariff is needed. However, we have contacted SSVEC and Staff in an effort to work together on a general form of Prepaid Service Tariff that can be used by both cooperatives, with appropriate modifications for their respective systems. Mohave encourages Staff to work expeditiously with SSVEC and Mohave to reach a consensus form of prepaid service tariff before rejoinder testimony is due in this matter at the end of March. In the event such a consensus tariff is timely developed, Mohave is willing to propose the consensus tariff in lieu of or in connection with its proposed Section 102-I, as appropriate based upon the tariff. However, Mohave is unwilling to abandon its Section 102-I before a consensus prepaid service tariff exists. Prepaid service is too important to our members to allow it to languish in a separate docket.

5. <u>RESIDENTIAL CUSTOMER CHARGE</u>

Q. Do you have any comments regarding Staff's proposed residential customer charge?

A. Mohave management proposed a $16.50 residential customer charge only after carefully balancing the cost of providing service as demonstrated by the cost of service study with the impacts on Mohave's member-customers. We considered the negative impacts to Mohave and its customers when 90% of its customers (i.e., its residential class) have a customer charge that does not come close to paying the fully allocated cost of merely accessing the system, without consuming a single kWh of energy. We addressed the impact of making a substantial move in the proper direction by keeping the overall rate increase to a minimum and moving from a single energy rate to a three tiered energy charge in such a way that customers using between 400 kWh to 1000 kWh will have minimum impact from the rate change. Yes, the percentage increase for those customers using 0 - 200 kWh per month will seem significant, but these energy use levels do not reflect residential dwelling units that are actually occupied for the full month, and the actual dollar increase for any customer using 400 kWh or less under Mohave's proposed rates will never be greater than $7 per month.

Q. Has the new rate structure Mohave is proposing been explained to its customers?

A. After filing the application we held a series of town hall meetings throughout the service area to explain the filing. While customers, as well as the Mohave Board, would prefer no increase, the application and rationale for the new rate design were supported by those attending the town halls. In fact we have received no negative comments about the customer charge Mohave is proposing.

Q. Does Mohave's elected board feel its determinations should be given substantial weight by the Commission?

A. While the Mohave board respects the Commission's Staff, it does believe that, as the elected representatives of the customers they serve, the Board's decisions should be given substantial weight and deference by the Commission. In reviewing the testimony of Mr. Erdwurm, I find no justification for the Commission to accept the Staff's proposed residential customer charge over the one recommended by Mohave's Board.

Q. Is Mohave willing to phase-in its proposed residential customer charge over a two year period?

A. While Mohave does not feel a phase-in of the residential customer charge is necessary, should the Commission feel strongly that the move to $16.50 in one step is too significant, we would accept starting with the $12.00 customer charge proposed by Staff on the effective date of the new rates, moving to $14.25 with November 2013 usage and then to $16.50 with November 2014 usage. As explained by Mr. Searcy, the energy charge for each tier would be proportionally reduced each step to achieve the approved revenues with test year billing determinants.

Q. Do you have any comments on any of the other rates design issues?

A. Again, the Commission should give substantial weight and deference to the rate designs proposed by the Mohave Board, as the elected representatives of the customers Mohave serves. Mr. Searcy sets forth Mohave's position on the various rates. Finally, the fact that the three existing customers on the large commercial & industrial time of use rates have taken advantage of a poor rate design, should not be construed as entitling them to perpetual subsidization from the rest of Mohave's customers. While Mohave feels the error should be corrected immediately, we again are willing to accept a phase-in of the appropriate rate design as more fully explained by Mr. Searcy.

6. PROPOSED $1.946 MILLION PRUDENCE PENALTY

Q. Do you have any comments on Staff's proposed $1.946 million prudence penalty?

A. The recommendation to charge Mohave a $1.946 million penalty based upon an unsupported claim that Mohave has not properly maintained and produced documentation to support its purchase power costs is baseless and if accepted will have a severe impact on the financial health of Mohave. To impose a penalty of this magnitude to avoid the mere possibility of sending "a signal that a utility can avoid scrutiny by failing to maintain records and file requested information" is unthinkable.

First, I note that when we met with Staff to discuss our filing in April of 2011, no member of Staff suggested Mohave would be subject to a prudence review of its purchase power practices; and certainly we were not told it could extend back as far as July 2001. Staff acknowledges that, though our application had been pending for 5 months and they were seeking proposals to perform a power purchase prudency review, we were first notified via electronic receipt of 76 multi-part data requests on September 1, 2011 (the Thursday before the Labor Day weekend). Under the procedural order we had 7 days to object. Weighing what we could reasonably supply promptly, the burdens of the request, the substantial period outside the test year involved and the fact that Mohave had regularly filed monthly purchase power reports with supporting data with the Commission, we timely objected to all requests seeking information prior to January 1, 2007. At no time has Mohave simply refused to maintain or provide data. We assumed if Staff had a need for additional information it would seek an order from the Administrative Law Judge, and/or make additional informal attempts to request specific information not included with previously filed purchase power monthly reports. At no time, prior to its filing of direct testimony did Staff suggest that our objection would result in its recommending a penalty, let alone a $1.946 million penalty.

Secondly, Mohave continues to purchase the bulk of its power from AEPCO at the rates approved by the Commission. Therefore, as Mr. Mendl recognizes, Mohave historically has acquired only about 7 to 10% of its power from sources other than AEPCO. The inequity of basing any penalty, assuming one was appropriate at all, upon power costs paid at Commission approved rates should be obvious.

Third, as Mr. Stover testifies, the penalty will have significant adverse impacts on the financial condition of the Cooperative.

We have advised Staff that if they will advise us of specific gaps in the data provided with our monthly purchase power filings, we will make a good faith effort to locate the missing data. We have not received such requests as of the filing of this rebuttal testimony. However, we are also deeply concerned the time necessary to locate data responsive to such requests at this late date in these proceedings will further delay resolution of our rate application, which is a result that will have its own adverse consequences on the Cooperative's financial condition. Mohave asks the Commission to summarily reject Mr. Mendl's recommendation.

7. LEGAL, CONSULTING AND STAFF PURCHASE POWER COSTS

Q. Do you have any comments on Staff's proposed removal of $594,737.45 from the fuel bank balance related to in-house labor, consulting, lobbying and legal purchase power costs?

A. The decision to charge these costs to the PPCA was made before I was CEO. However, I know that the expenses can be significant, are largely dictated by things beyond Mohave's control and therefore somewhat variable month to month. I also understand that had these costs not been collected through our PPCA, Mohave's financial performance would have been adversely affected. The way I analyze the issue is that these expenses are directly incurred in securing, scheduling, documenting and reporting purchase power. When we purchase power, I know these same costs are included in the cost we pay for the power we are purchasing. Therefore, to me these charges are properly charged to the members through the PPCA.

While Mohave prefers to continue collecting these costs through the PPCA, if the Commission orders that we cease doing so, and to recover them through base rates as Staff recommends, then the Commission should make the change effective with the new rates and without adjusting the bank balance for amounts previously charged to the PPCA. As Mr. Stover and Mr. Searcy explain, these costs were properly incurred and chargeable to the ratepayer. We know of no Commission rule or order that prohibited Mohave from booking these costs as purchase power related costs and collecting them through the PPCA. As Mr. Stover explains, having 2 ½ years of these expenses hit the income statement in 2012 will severely undermine Mohave's financials and negate the positive impact of the rates the Commission will be approving. Finally, as a cooperative, the customer-owners will be adversely impacted by the negative financials and, as explained by Mr. Stover, the refunds will be disproportionately distributed to certain customers based upon off-peak usage.

8. THIRD PARTY SALE

Q. Do you have any comments on Staff's proposed treatment of Mohave's third party sales?

A. Mr. Stover explains this issue. I will add that the reasons Mohave management opposes Staff's recommendation is that it deprives the member-customers of the long term advantages of healthier margins and financials which will translate into lower rates and more capital patronage. These benefits are lost in order to secure short term reductions in the PPCA rate. Mohave believes that the existing treatment remains in the best interest of the Cooperative and its members.

9. NEXT RATE FILING

Q. Do you have any comments on Staff's recommendation that the Commission order Mohave file its next rate case by April 1, 2016 using a 2015 test year?

A. Compelling Mohave to file a rate case by any specific time or using a specific test year as part of this case unnecessarily and inappropriately removes the management prerogative to make these determinations from the duly elected representatives of Mohave's customers – the Mohave Board of Directors. The sole justification provided for Staff for requiring the filing by 2016 is to ensure a timely prudency review of Mohave's purchase power practices. A rate case is not needed for the Commission to conduct a prudency review of Mohave's purchase power practices. Moreover, Mohave respectfully requests the Commission significantly simplify the prudency review process for partial requirements distribution cooperatives under its jurisdiction. We would be glad to work with Staff and the other partial requirements distribution cooperatives to develop a streamlined reporting and review process.

10. STREAMLINED RATE PROCESS

Q. Do you have any comments on the rate process that you would like to share with the Commission?

A. This is the first time I, and most of Mohave's current staff, have been involved in a rate case before the Commission. I appreciate Staff's willingness to discuss and try to resolve contested issues in a fair and equitable manner. However, the process is unnecessarily cumbersome and costly for non-profit electric distribution cooperatives. While the Commission's existing rules envision a simplified rate application composed chiefly of a Form 7 and a current audited financial statement, it is unlikely such an application would ever be found to be sufficient. In addition Staff's insistence on a supplemental 2010 test year (versus relying on the 2009 test year selected by Mohave) and its decision to conduct a prudence review of purchase power costs back to July 2001 substantially complicated and increased the costs of this proceeding (increasing rate case expense from an anticipated $150,000 to over $400,000), not to mention delayed the needed rate relief.

Mohave asks the Commission to act swiftly on streamlining the rate case process for non-profit cooperatives so that a request for less than a 4% rate increase after 20 years can be implemented at less cost and on a more timely basis.

Q. Does this conclude your testimony?

A. Yes, it does.

5. Service establishment shall be made only by qualified Cooperative service personnel.

6. For the purposes of this rule, service establishments are where the Customer's facilities are ready and acceptable to the utility and the utility needs only to install or read a meter or turn the service on.

7. The Cooperative shall attempt to schedule all service establishments in accordance with the above provisions. However, service establishments for security and street lighting may be assigned a lower scheduling priority than other service requests.

SUBSECTION 102 - H: NET METERING

1. The Cooperative shall offer net metering to the Customer.

   a. The net metering option shall be offered to the Customer based on the ACC approved net metering tariff.

   b. The Cooperative will install the proper net metering equipment upon the completion and inspection of the Customer's generation system and the filing of all enrollment forms requested by the Cooperative based upon the approved net metering tariff.

SUBSECTION 102 - I: PREPAID METERING

1. Where the Cooperative has the capability of doing so, it shall offer prepaid metering to residential Customers receiving Permanent Service as an option to alleviate the financial impact of paying a cash deposit to the Cooperative or purchasing a surety bond for service. Prepaid Metering shall be offered under the following terms and conditions:

   a. The residential Customer shall prepay an agreed amount upon subscribing to the prepaid metering option.

   b. The residential Customer shall have the ability to access their current consumption and remaining prepaid balance by utilizing the Cooperative's website.

   c. In lieu of written notice pursuant to Subsection 111-C, the Cooperative shall notify the Customer by electronic mail, where provided, and by interactive voice response phone call at the number provided by the Customer reminding the residential Customer that additional prepaid funds are necessary as the current prepaid amount becomes nearly consumed.

   d. The residential Customer may make subsequent prepayments as often as desired by making payments in person at the Cooperative's office, or by mailed check; or at anytime, including after hours, by utilization of the Cooperative's electronic payment system found on the Cooperative's website, or by utilization of the Cooperative's voice-activated response telephone payment system at no cost in fees to the residential Customer.

   e. Should the residential Customer neglect to make payment prior to the total of their prepaid balance and disconnection occurs, the residential Customer can make a payment, including the applicable Service Reconnect Charge, through any of the means described above in paragraph (d) in order to have their service reconnected. The Cooperative will endeavor to reconnect the service within two hours of the time the payment is made.

f. Any residential Customer of the Cooperative may opt in or out of the prepaid metering option at any time; however the residential customer may change options no more than two (2) times in a calendar year including the initial election of the prepaid metering option.

g. Any residential Customer who opts out of the prepaid metering program continuing service with the Cooperative will be required to reestablish credit with the Cooperative as set forth in Subsection 102-E; provided, however, utilization of the prepaid metering option for a period of twelve (12) consecutive months without disconnection of service shall have demonstrated the establishment, or re-establishment of satisfactory credit with the Cooperative and may elect to opt out of the prepaid option without obligation to post a deposit for continuing service.

Attachment CA-10.7

Mohave Electric Cooperative (MEC)
Prepaid Metering Agreement

The Prepaid Metering Program (the "Plan") is a program option to MEC customers who desire to alleviate the financial impact of posting a deposit or otherwise securing their service account. The Plan is designed to give the member more control over their electric usage and more opportunities to reduce their electricity costs. Some of the plan's features that are designed to help members include:

- No requirement for a security deposit
- Smaller, more frequent payments can be made on the account
- Avoid late fees
- Monitor usage daily

Payments can be made on the Plan utilizing any of MEC's payment systems, including on line payments, electronic telephone payments (1-877-371-9379, select Option#1) and payments at our Customer Service office during normal MEC business hours. The Plan offers the members access to their current and historical consumption to assist them in managing their prepaid service. This history can be accessed with a secured member login at MEC's member website and is updated once each business day. At the MEC website the member can also update their contact information. The member will need to register online at the website in order to access their information.

Mohave's Prepaid Metering Program is available to standard residential customers where Mohave has installed the new AMI digital metering technology and can connect and disconnect your service remotely so no serviceman is needed to be dispatched.

- **Electric service is subject to immediate disconnection any time an account does not have a credit (prepaid) balance, even if the customer has submitted medical documentation that termination would be especially dangerous to a permanent resident of the premises or where life supporting equipment dependent on utility service is in use.**
- Members can access their balance on the MEC website or by calling MEC during normal business hours (1-877-371-9379).The information is updated each business day.
- The member will receive warning notices of low prepaid balances ($50.00 or less) on their account by recorded voice messages to the member's designated contact phone number, and by email to the member's designated email address. These messages will be sent daily until the prepaid balance is exhausted.
- The prepaid account will be disconnected during MEC business hours on the first day that the account no longer has a prepaid balance. It will be the member's responsibility to make adequate payment to bring their account back to a prepaid balance of at least $20.00. Upon payment of a new prepaid amount service will be restored no later than the following business day.

Prepaid accounts will be administered in accordance with MEC's Rules and Regulations, approved by the Arizona Corporation Commission, that apply to Prepaid Metering (Subsection 102-I), as amended from time to time.

- Member authorizes MEC to charge their prepaid account for electric services rendered in accordance with the Rules and Regulations of the Cooperative.
- Member has the ability to access to their consumption history as described above and it is their responsibility to utilize the balance information and their consumption in order to maintain a prepaid balance in their account at all times to avoid disconnection of service.
- Member is responsible for maintaining accurate contact information including telephone number, email address and mailing address at all times.
- Member *Holds Harmless MEC, its directors, officers, employee and agents* for damages resulting from disconnecting service in accordance with approved tariffs and rules and regulations of the Cooperative.

I have carefully read and I understand the terms within the Mohave Prepaid Metering Agreement and understand the difference between prepaid service and standard residential (post paid) service. I am requesting that MEC establish prepaid electric service for my account.

Account Number______________________________

Member Signature______________________________ Date________________________

Member Signature______________________________ Date________________________

Contact Mailing Address____

Contact Email Address___________________ Contact Telephone Number_______________

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
OCTOBER 3, 2011

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

The Following Questions Relate to the Proposed Rules and Regulations

Section 102-Establishing Electric Service

CA – 5.31 Please explain why Mohave is proposing the implementation of prepaid service. In addition, please provide the following information:

A. Should a customer who has been a standard billing customer and has been required to post a deposit choose to elect prepaid service, would the deposit paid be refunded to the customer or applied to the prepaid service?

B. Would a customer be required to pay any additional fees for switching to prepaid service?

C. Would a customer be required to pay a reconnection, establishment, or reestablishment fee should the customer choose to change service methods? If so, would the fee be different than the proposed reconnection, establishment, or reestablishment fees included in the application?

D. Subsection 102-I(1)(g) of the proposed rules and regulations states that a customer who switches from prepaid service and has utilized the service for 12 consecutive months without disconnection would have demonstrated satisfactory credit. The customer would then be able to switch from prepaid service to standard billing service without being obligated to post a deposit for continuance of service. Please clarify the following:

   1. Would a customer who switched from prepaid service after less than 12 consecutive months without disconnection be required to post a deposit for continuance of service?

E. Would Mohave provide an in-home display unit that would allow the customer to track his/her usage on a daily basis? If so, please indicate what the cost to the customer would be for an in-home display unit.

F. Would a customer on prepaid service be able to pay for prepaid service using an automatic withdrawal method?

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
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Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

G. Should a prepay customer be disconnected, would the customer be required to pay a deposit or reconnection fee to reconnect to prepay service?

Response: **Customers who are seeking to establish service, especially after being disconnected for nonpayment, often find it difficult to post the deposit. As Mohave's system and meters are enhanced, it will have the ability to log the customer's daily usage, as well as to establish and disconnect service remotely. Where such capability exists, Mohave desires to offer its members the option of prepaid service in lieu of requiring deposits.**

The responses to the subparts are as follows:

A. The Deposit would first be applied against any outstanding bill. Once the remaining deposit is subject to refund pursuant to 102-C.3.c., the customer would have the option to have it refunded or applied to their prepaid account.

B. Yes. An Establishment Fee will be charged to recover time and materials related to setting up the prepaid metering service. The account and member information must be manually entered into the prepayment system which interfaces with the automated meter and disconnect collar that will communicate with the system. In cases where it a disconnect collar is not in place, it must be installed, which involves a physical visit to the customer's premises. No additional charge, above the Establishment Fee is made where installation of a disconnect collar is required.

C. Same as response to B above.

D. Yes. Subsection 102-I(1)(g) makes it clear that any customer opting out of the prepaid metering service must meet one of the establishment of credit criteria under Subsection 102-C. Subsection 102-I(1)(g) merely reflects that 12 months of uninterrupted prepaid meter service satisfies the criteria of Subsection 102-C(1)(a)(1)(a).

E. No. Mohave's system will not have that capability. Usage information can be obtained by the customer by phone, the internet or directly from Mohave. It will not be instantaneous usage information but will be updated at least twice a day. The prepaid meter service customer will

also receive notice pursuant to Subsection 102-I(1)(d) through email or phone to make another payment to avoid disconnection when the current prepaid amount becomes nearly consumed.

F. The proposed rule does not provide for automatic withdrawals. This may be possible, but would take some investigation and discussion with financial institutions to determine its availability and practicality. Mohave is uncertain whether those using prepaid metering service because of an inability to post a deposit would have both an account at a financial institution and have that account funded.

G. While a prepaid customer that is disconnected would be subject to the same charges as any other Mohave customer that is seeking service and could be charged the Establishment of Service Fee, Mohave does not intend to charge the Establishment of Service Fee where a prepaid customer is disconnected for less than thirty (30) consecutive days.

Prepared by: Mike Searcy
*

CA – 10.1 **Will the proposed prepaid metering option be available to residential TOU customers?**

Response: No. Mohave's prepaid metering option is available to standard Residential customers receiving permanent service, where the Cooperative has the capability of doing so, as an option to alleviate the financial impact of paying a cash deposit to the Cooperative or purchasing a surety bond for service. Mohave proposed Subsection 102-I(1). It was not intended for optional services, such as TOU, Demand or Net Metering. Currently there is no capability of providing the option to these classes of customers, so they are excluded.

CA – 10.2 **Please specify under what conditions Mohave would not disconnect a prepaid metering customer.**

Response: All prepaid customers will be disconnected once prepaid balances are exhausted in accordance with the notice provided (See also Response to CA-10.16). Note, disconnections will occur only during Mohave's normal business hours and not on nights, weekends and holidays.

CA – 10.3 **Please clarify if the prepaid metering service would be available to both residential single phase and three phase customers.**

Response: Mohave's prepaid metering service is available only at service locations where advanced metering infrastructure is operational and an AMI digital meter is installed. Due to the absence of automated three phase technology and remote disconnect capability, prepaid service currently will be unavailable to residential three phase customers. Mohave would entertain three phase customer service prepaid options in the future once reliable technology is proven.

CA – 10.4 **Will the proposed prepaid metering option be available to residential net-metering customers?**

Response: Not at this time; again, for the same reason identified in Response to CA-10.3 (technology). Mohave currently only has 166 net metering customers.

CA – 10.5 **Does Mohave intend to propose a separate tariff available to potential prepaid metering customers? If so, please state if Mohave will include daily rates for the charges specified in the proposed Standard Offer Residential Service Tariff. In addition, please include an electronic spreadsheet with all calculations.**

Response: Prepaid service is proposed to resolve the issue of requiring a deposit or surety for residential service. Mohave included the option in its Rules and Regulations just like other deposit provisions and does not intend to propose a separate tariff, as it will use the same billing components as Standard Residential Service.

Mohave is willing to consider a separate tariff for prepaid metering if Staff believes one is necessary.

CA – 10.6 **How would a prepaid metering customer be charged for the Commission approved REST adjustor rate or any other adjustor rate the Commission may approve? Would a daily rate for the surcharges be included in the respective tariffs?**

Response: Any adjustor such as REST will be programmed into Mohave's billing system and be charged on a per kWh basis. Mohave's software has the capability to perform "micro billings" that accumulate over a normal billing period of time (month) that allow the adjustors to be charged until any cap is reached if a cap exists.

Mohave is not proposing a separate tariff at this time. (See Response to CA-10.5)

CA – 10.7 **Will a customer be required to sign an agreement with Mohave for prepaid metering service? If so, please provide Staff with a copy of the proposed agreement.**

Response: Customers utilizing Mohave's prepaid metering option will be required to sign a prepaid metering agreement. A copy of Mohave's proposed Prepaid Metering Agreement is provided as Attachment CA-10.7.

CA – 10.8 **Will a customer have the ability to obtain an estimate of how long a prepaid credit amount would last based on the customer's current usage and/or up to the previous 30 days of consumption prior to activating a prepaid metering account?**

Response: Mohave residential customers utilizing the prepaid option will have the ability to obtain an estimate of how long a prepaid credit amount would last based on their current usage. Customers can also obtain information on their usage over any period of time (day, week, month). The consumption information is updated daily. The information can be obtained by the customer not only during business hours at Mohave's business offices, but also online by accessing their account information on Mohave's website.

The customer will have the ability to obtain statistical information on their account at service locations where advance metering infrastructure is operational and an AMI digital meter is installed.

CA – 10.9 **If a customer receiving standard service is disconnected for non-payment and has an outstanding balance and chose to re-establish service under prepaid metering would the customer be required to pay the full balance of the previous bill prior to obtaining prepaid service?**

Response: A customer re-establishing service under the prepaid metering option with an outstanding balance would be afforded the option of a payment agreement as outlined in Mohave's Rules and Regulations under Subsection 110-G. The concept of the prepaid metering option is to alleviate the financial impact of the deposit on the Customer, while at the same time avoiding financial loss to the Cooperative. If the customer declines a payment arrangement the total balance would be due prior to obtaining prepaid service.

CA – 10.10 **Will a customer with an outstanding balance prior to obtaining prepaid service be eligible for a payment arrangement? If so, please indicate if the amount that would be required in excess of the actual payment would be a set dollar amount or a percentage of the unpaid balance. In addition, would the customer be required to pay the balance within a specific time frame?**

Response: Yes. See Response to CA-10.9. The amount required for a payment arrangement would be 50% of the outstanding balance, with the remainder of the balance being paid in up to six monthly installments thereafter. The amount of the installments thereafter would then establish the set dollar amount depending on the number of payments selected by the customer. The customer would be required to pay the entire outstanding balance within six months using the payment arrangement.

CA – 10.11 **If the customer does not pay the outstanding balance (according to the payment arrangement) within the specified time frame, please describe the disconnection policies Mohave would follow.**

Response: If a prepaid customer does not pay the outstanding balance according to the payment arrangement within the specified time frame, but otherwise is maintaining a positive prepaid balance, Mohave would then follow the "Termination of Service With Notice" rules as outlined in Mohave's Rules and Regulations under Subsection 111-C. If service was disconnected any credit balance on the prepaid metering account would be credited against the defaulted payment arrangement.

CA – 10.12 **Will customers have the ability to combine multiple accounts into a single bill?**

Response: No. Customers who take the prepaid metering option will not be able to combine accounts.

CA – 10.13 **Will Mohave provide extensive explanation of the potential risks of prepaid metering for those customers specified under A.A.C. R14-2-211.A.5 and for those customers under appropriate circumstances but beyond the scope of A.A.C. R14-2-211.A.5?**

Response: Since the prepaid metering service is an option to standard service, Mohave's Prepaid Service Agreement will explain differences between the two services, including the potential risks of prepaid metering for those customers specified under A.A.C. R14-2-211.A.5 and for those customers under appropriate circumstances but beyond the scope of A.A.C. R14-2-211.A.5.

CA – 10.14 **Does Mohave have or use a definition for Extreme Weather Days (or Conditions)? If not, how does Mohave determine the weather conditions that would qualify as Extreme Weather Days (or Conditions)?**

Response: Mohave does not use or propose a definition of "Extreme Weather Days" but proposes a definition of "weather especially dangerous to health" substantially similar to A.C.C. R14-2-201.46. See subsection 101(58) of proposed Rules and Regulations. This term is used in subsection 111-A(1)(d)(3) of Mohave's Rules.

CA – 10.15 **Does Mohave intend to disconnect prepaid metering customers during Extreme Weather Days (or Conditions)?**

Response: No. Mohave does not intend to disconnect prepaid metering customers during weather occurrences that would fall within the definition given under A.C.C. R14-2-201.46 and Mohave's subsection 101(58). Such occurrences are highly unlikely in Mohave's service territory.

CA – 10.16 **If a customer's credit balance is less than the current daily average usage, would notice be given to the customer on a daily basis? If so, what would be the amount of the credit balance that would trigger the notices? In addition, please explain how the amount of the credit balance is determined.**

Response: A credit balance that falls below $50.00 would activate the notification system to afford the customer with daily notices prior to their prepaid balance being exhausted. The notices would be sent via the Cooperative's Interactive Voice

Response System and by emails to the customer's email address of record. Mohave's software system performs daily "micro billings" which deduct daily consumption and adjustors that produce a "new" credit balance daily.

CA – 10.17 **If a customer converted from prepaid metering service, what is the minimum timeframe he/she must wait in order to be eligible to re-apply for prepaid metering service at the same location?**

Response: There is no timeframe a customer must wait in order to be eligible to re-apply for prepaid metering service at the same location; however, Mohave's proposed Subsection 102-I.1.f., limits a customer opting in or out of the prepaid metering program to twice in any consecutive twelve month period of time.

CA – 10.18 **Does Mohave require its customers to pay a membership fee? If so, what is the amount of the fee charged to its customers (per customer class, if applicable)?**

Response: Mohave requires its customers to pay a $5.00 membership fee for standard residential service.

CA – 10.19 **Would Mohave require an additional membership fee be paid by a customer who converts to prepaid metering service?**

Response: No. Each member pays only one membership fee.

CA – 10.20 **Would Mohave transfer the existing membership fee amount to a customer's prepaid metering account? If so, would Mohave require an additional membership fee be paid by customers who convert to prepaid metering service from standard service?**

Response: Not Applicable. See Response to CA-10.19.

CA – 10.21 **If prepaid metering service is terminated at the request of the customer (who converts to standard service) and results in a refund, would the amount be credited to any deposits or fees required for standard service?**

Response: Yes, any remaining balance would be credited to any deposit or fees required for standard service.

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01750A-11-0136

EXHIBIT
MEC-8

REJOINDER TESTIMONY OF

J. TYLER CARLSON

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

March 30, 2012

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REJOINDER TESTIMONY OF
J. TYLER CARLSON
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INCORPORATED
SUMMARY OF REJOINDER TESTIMONY

Mr. J. Tyler Carlson, Mohave's Chief Executive Officer, through his Rejoinder testimony:

1) Provides further support for a residential customer charge of $16.50;

2) Further explains Mohave's proposed prepaid service program;

3) Explains why Staff's proposed special frozen rate for three existing Large Commercial & Industrial time-of-use customers is unreasonable and unfair to other customers;

4) Encourages Staff and Mohave to cooperatively develop a mutually acceptable purchase power records retention plan; and

5) Encourages the Commission to allow the Mohave Board to determine when to file its next rate case rather than to set an arbitrary filing deadline and to expeditiously complete its separate rulemaking efforts to streamline the rate adjustment process for cooperatives.

1. INTRODUCTION

Q. Please state your name and your position with Mohave Electric Cooperative, Incorporated.

A. My name is J. Tyler Carlson. I am the Chief Executive Officer of Mohave Electric Cooperative, Incorporated ("Mohave" or "Cooperative").

Q. Have you previously testified in these proceedings?

A. Yes, I have submitted rebuttal testimony in this proceeding.

2. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to Staff's positions following its surrebuttal testimony on the following issues:

1. The residential customer charge
2. Prepaid Service
3. The Large Commercial & Industrial time-of-use rate
4. Staff's Purchased Power Prudency review
5. Our next rate case filing and streamlining

3. CUSTOMER CHARGE

Q. Why is Mohave unwilling to accept Staff's proposed $13.50 residential customer charge?

A. Mohave appreciates Staff's willingness to move its recommendation on the residential customer charge from $12.50 to $13.50. However, a major objective of this rate filing is to develop and adopt cost based rate designs that are understandable, provide appropriate pricing signals, encourage energy conservation and are fair and equitable to our member/customers. Mohave's current rate designs were implemented in January 1991. Much has happened in the utility industry since that time. Additionally, Mohave is actively installing modern metering and billing technology to enable us to implement and monitor the impacts of the new rate designs we are proposing.

A key component of our updated rates is to establish cost based customer charges, coupled with energy tiers with inclining rates that more accurately reflects the cost of providing electric service to Mohave's member/customers. While the Staff's proposed $13.50 customer charge is an improvement, it still does not recover enough of the base cost of service and therefore is not supported by Mohave. In response to Staff's concerns regarding moving all the way to $16.50 at this time, we have offered the alternative of starting initially at the customer charge level supported by Staff and phasing in the remaining in the additional $3.00 over reasonable period. Our proposal is two equal steps over the winter seasons (lower energy use time) of 2013 and 2014.

Q. Does Mohave agree with the Arizona Corporation Commission's ("Commission") determination in Decision No. 71230 that customer service cost includes "distribution line expense, a portion of the transformer expense, the meter and service drop expense, and meter reading and customer records expenses."? (Decision No. 71230, page 7 at lines 18-20)

A. Yes. Mohave agrees with that determination and opposes Mr. Erdwurm's suggestion that "the default position in future Mohave rate cases should be that no portion of poles, lines and transformers is classified as customer-related without some study supporting the magnitude of customer component." (Erdwurm Surrebuttal at page 3, line 25) Mohave's cost of service study (COSS) provides any additional justification needed beyond prudent ratemaking principles to reject this proposed default position. Each Mohave member/customer should be responsible for a reasonable portion of the distribution and transformer expense associated with providing the minimum level of service to any customer as these costs are fixed and do not vary with the amount of energy consumed. In this instance, the Mohave Board of Directors included $16.50 of the $18.56 in customer-related costs in the customer charge. The Commission should respect the determination of the member/customers elected representatives and approve the $16.50 customer charge in this rate case whether in one step or phased in over a period of time.

Q. Are bills reflecting usage of under 400 kWhs reflective of full-time residents?

A. I believe few full-time residents consume under 400 kWh per month. An examination of the average energy use by typical appliances supports this belief. Mohave Rejoinder Exhibit JTC-1 is a chart posted by City, Water, Light & Power of Springfield, Illinois on its website providing representative kWh usage by various appliances. The use of just a water heater by a family of 4 reaches 400 kWh per month. A post 2002 refrigerator alone consumes 82 kWh per month and a 14 SEER air conditioner uses .85 kWh per hour which results in an energy efficient air conditioner running 6 hours a day 30 days a month consuming over 150 kWhs). Thus the energy usage of just these three common appliances alone, and assuming more efficient models, can be expected to exceed the 400 kWh level.

Q. Are there a lot of part time and transient residents in Mohave's service territory?

A. We do not have specific statistics, but a large segment of the population is either part time or transient. We have a significant influx of winter visitors especially in the Bullhead City/Colorado River portion of our service area. The energy use of these customers is currently being heavily subsidized by our full time residents. At the town hall meetings we held related to the rate filing, the member/consumers were very supportive of increasing the customer charge to eliminate this subsidization.

4. PREPAID SERVICE

Q. Do you have any comments on Staff's surrebuttal relating to the prepaid metering service Mohave wishes to implement?

A. First, we thank Staff for providing some guidance on the subject in its Surrebuttal. We also appreciate Staff's willingness to meet with us recently to discuss Mohave's prepaid service program. Shortly before meeting with Staff, we distributed a rough draft prepaid metering tariff and a revised prepaid metering agreement in an effort to address many of the comments appearing in Ms. Allen's surrebuttal at pages 2-4. Mohave believes the discussions were productive and have resulted in a further refinement of both the proposed prepaid service tariff and prepaid service agreement. Copies are provided as Mohave Rejoinder Exhibits JTC-2 and JTC-3, respectively. At Staff's request, I will also further explain the proposed prepaid plan as part of this Rejoinder Testimony. We remain willing to work with Staff during the course of this proceeding on further refinement of both documents as well as revising Mohave's service rules and regulations, as necessary, to be consistent with the proposed prepaid service tariff and prepaid service agreement.

Q. Who is eligible for prepaid service?

A. Prepaid service is available to existing and new customers who otherwise would be on Mohave's standard service residential Schedule R. It is not available to time-of-use customers, net metering customers, customers on Mohave's Energy Balance Plan (levelized payments) or to critical need customers (i.e., customers who have provided a medical notification in compliance with Subsection 111-A.1.d.(1) of Mohave's rules indicating that electrical service is critical to their health). The service is only available to single phase customers who have AMI meters and where Mohave has installed the necessary backbone equipment necessary to support prepaid metering service in their area.

Q. Can you briefly describe the technology involved in this service?

A. Mohave is installing Cooper Power AMI equipment that is integrated with our Customer Information Systems that allows real time interchange between the two systems. Disconnect collars can be installed at the meter that can be controlled via our Power Line Carrier connectivity.

Effectively, Mohave receives daily usage information and its billing computer performs Micro Billing for each day of service. The Micro Billing prorates the customer charge as well as tracks the REST surcharge to ensure the surcharge does not exceed the applicable cap for residential customers. The data is compiled monthly on the customer's normal billing cycle, which resets the customer charge and REST surcharge computation for the upcoming cycle.

Paper billing statements are generated. The customer has access to their historical usage data through Mohave's website and by contacting Mohave's business offices. The website is accessed through normal log-in specific process including a user name and password. The computer program displays usage as daily averages. More specific detail on daily use can be obtained by contacting Mohave's business offices during normal business hours.

Q. Will Mohave be disconnecting prepaid customers in the evening, on weekends or on holidays?

A. No. Disconnection will only occur during normal business hours which exclude holidays and weekends. Mohave's billing system will generate the Micro Billings daily, usually around 10 p.m. If the balance is zero or less the account will be scheduled for disconnection the next business day. We anticipate remote disconnection will usually occur between 9 and 11 a.m.

Q. How does the customer know the status of their account?

A. They will have three alternatives to review the billing status of their account. They can make a phone call to our IVR system for balance inquiries and payments. They can inquire by internet which also provides balance information and allows for payments as well. The website also provides monthly costs (dollars paid per month for the full bill), the average cost (average daily cost by month), monthly usage (kwh per month) and the average usage (average daily kwh usage per month). Finally they can contact any of Mohave's business offices. Cash payments must be made at Mohave's business offices.

Q. Will Mohave be providing the customer notification prior to disconnection?

A. An email, text message and/or phone message, as specified by the customer, will be sent daily after the account reaches a predetermined dollar level. After discussions with Staff, our tariff proposes three seasons with different notification levels:

October 1 – February 28 (29) at $25.00 or less

March 1 – June 30 at $35.00 or less

July 1 – September 30 at $50.00 or less

We will require at least two means of notification, one of which could be to an authorized agent designated by the customer.

Q. Once disconnected, how does a prepaid customer re-establish service?

A. After they bring their prepaid balance to at least twenty dollars, we will reenergize the service. No other charges are incurred unless the account is closed. Accounts will not be closed until the end of a billing cycle but not less than ten days after the disconnect. In such case, a separate notification will be provided to the customer that their account has been closed and a final bill will be generated. If the account has been closed, the customer will also have to pay the standard Establishment Fee to re-establish prepaid service.

Q. Is there anything else the customer must do to reconnect prepaid service?

A. For the customer's safety and that of their property, our system is not designed to automatically restart when reenergized. There is a reset button at the meter that the customer must push once the account has been reenergized. This ensures that the customer is aware that they are about to reenergize their house and had an opportunity to take the necessary precautions, such as turning off sensitive electronic equipment, prior to reenergizing the account.

Q. Do you have any other comments regarding prepaid service?

A. I believe that the tariff and agreement clarify the way the prepaid service works and we appreciate Staff's assistance in developing a clearer program. As to Staff's suggestion that this service should be subject to a separate docket and further public comment, Mohave opposes any action that would delay implementation of the service. Our member/customers are anxious to have this option. One must remember prepaid service is an option. No customer is required to take prepaid service.

We will be observing the system and feedback from customers based upon actual service experience. If further refinements of the services are necessary, Mohave is open to refining the service conditions and process within the limits of the equipment that we have. Mohave's system is not designed to support some components of other prepaid service programs, such as in-house monitors.

Q. Why isn't Mohave proposing this as an experimental program?

A. We want to make the program available to all existing and prospective customers that qualify rather than setting an arbitrary limit on the number of customers that can participate. Mohave staff believe they will be able to administer the program efficiently without such limits. Therefore, we do not see the need to treat this as an experimental program.

5. LC&I TOU RATE

Q. Staff proposes to create a special frozen rate for the three existing Large Commercial and Industrial time-of-use (LC&I TOU) customers. Do you have any comments on Staff's proposal?

A. Staff now recognizes the current LC&I TOU rate is poorly designed and that the three customers on that rate have been getting electricity at rates subsidized by the rest of the member/customers. (Erdwurm Surrebuttal at page 10, line 11) That subsidization was unintended. The new LC&I TOU rate, which both Staff and Mohave agree is appropriate for new customers, eliminates that inequity but still provides savings over the standard LC&I rate. Mohave does not support creating a special subsidized rate for three existing customers. As large commercial and industrial customers they can be expected to have enough sophistication and means to alter utility usage through methods other than receiving an unintended subsidy. However, Mohave is not insensitive to the large percentage increase involved in moving these customers to a properly designed time of use rate. For this reason we are willing to phase-in in the new rate, as more fully discussed by Mr. Searcy.

6. PURCHASED POWER PRUDENCY REVIEW

Q. Do you have any general comments relating to the purchased power prudency review conducted by Staff in this proceeding?

A. Mohave complements Staff on the thoroughness and professional prudency review performed on Mohave purchase power practices in this matter. The time and effort involved for both sides could have been significantly reduced had Mohave been informed in 2001, when it became a partial requirements customer, that such a prudency review would be conducted during its next rate case since becoming a partial requirements customer of APECO. Additional clarity as to the type of record keeping expected by Staff would not only have been helpful in the current prudency review but would be helpful in the next prudency review. This is why Mohave wishes to work with Staff, (and other partial requirements customers) to develop a meaningful, and mutually agreed upon, records retention program that will facilitate such reviews in the future.

Undoubtedly, the prudency review significantly complicated what Mohave anticipated would be a straight-forward rate adjustment proceeding. It added significantly to the cost of this proceeding and has delayed implementation of needed rate relief. Mohave believes it is in the interest of the Commission, Mohave and Mohave's member/customers for the Commission and Mohave to work together to simplify the next prudency review. A blanket requirement such as proposed in Mr. Mendl's Recommendation 13 that Mohave "maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures" places an unreasonable burden on Mohave to guess as to the type of documentation that will satisfy Staff. Mohave is not seeking to be relieved of its responsibility to maintain reasonable documentation to support its purchased power activities. Mohave only seeks Staff's guidance and assistance in developing the type of record retention system to facilitate the prudency review process.

Q. Do you have any comments on Staff's recommendation (Mendl Recommendation 18) that the Commission require "MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period"?

A. As Mr. Stover addresses in his Rejoinder Testimony, we have been working with AEPCO for a number of years to improve the relationship between AEPCO's rates and the incurrence of costs. There is no need for the Commission to include requirements where there is an ongoing effort to address the issue.

Q. Do you have any comments on the various adjustments to Mohave purchased power bank balance and to the operation of its PPCA made by Mr. Mendl (Recommendations 2, 4-8, 10, 12, 15 and 16)?

A. Messrs. Stover and Searcy will address these specific Recommendations. However, I believe the PPCA bank balance should not be adjusted even if the Commission orders Mohave to stop including the purchased power supply-related consulting, legal and in-house staff expenses in the PPCA. There will be no double collection as the dollars generated from the new rates will be used to pay these costs as they are incurred in the future, not to reimburse Mohave for past expenditures.

I also continue to believe that Mohave's member/customers receive more benefit when margins from third party sales are treated as income to the Cooperative rather than to merely offset the cost of purchased power.

7. NEXT RATE CASE/STREAMLINING

Q. Do you have any further comments related to Staff's recommendation (Mendl Recommendation 11) that Mohave be required to file a rate case no later than September 1, 2016?

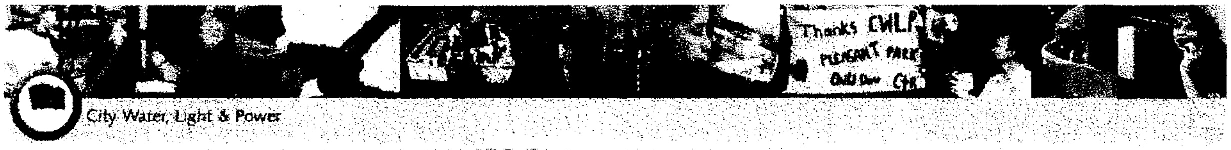
A. Staff nowhere addresses the fundamental question: Why should the decision as to when to file Mohave's next rate case be removed from the Mohave Board of Directors – the elected representatives of the customers they serve? The recommendation for a rate filing no later than September 1, 2016 does not have anything to do with the financial condition of Mohave. Rather Staff is concerned with the amount of data that might be involved in reviewing Mohave power purchases for prudency. Staff's concern simply does not justify compelling Mohave to incur the cost of a full rate filing if Mohave's financial condition does not warrant filing a rate case.

Q. Do you have any comments on Staff's recommendation (Mendl Recommendation 14) that Mohave be ordered to meet with Staff to discuss ways to streamline future Mohave rate cases?

A. I believe Mr. Mendl is confusing streamlining the rate case process with clarifying the purchase power record retention requirements of the Commission. My comments on Rebuttal relating to streamlining the rate case process were aimed at expeditiously concluding the ongoing and separate rule making process (Docket No. ACC-00000B-11-0308). I was not advocating a separate rate streamlining process specific to Mohave. The focus should remain on streamlining the rate process for all cooperatives.

Q. Does this conclude your Rejoinder testimony?

A. Yes, it does.



Appliance Energy Use Chart

The Appliance Energy Use Chart below is designed to give you an idea of how much electricity is consumed by many of the most common household appliances. Except where noted, the figures used in the chart have been based on the typical efficiency levels of appliances found in Springfield homes audited by the CWLP Energy Experts and on the price per kilowatt-hour paid by the "average" CWLP residential customer. Appliances with efficiency levels much lower or higher than the norm might consume significantly *more or less* energy than indicated on this table.

To translate the usages given in this chart into energy dollars, simply multiply the appliance's kilowatt-hour (kWh) usage by your average price per kWh (see the **NOTE** below for more about this) and the amount or number of times you use the appliances over a specific period.

> **NOTE: Based on current electric rates and the State Utility Tax, plus the average fuel adjustment charge for the previous year, the average annual cost per kWh of electricity paid by CWLP's regular (not all-electric) residential electric customers is approximately 9.5¢. For all-electric residential customers, the average annual cost is about 8.9¢ per kWh. (*Cost-per-kWh estimates were last updated September 30, 2008.*)**
>
> **More information about residential electric rates or business electric rates can be found elsewhere on this website.**

For instance, using the average cost-per-kWh provided in the **NOTE** above and the energy consumption information provided in the Appliance Energy Use Chart, we can calculate that it will cost a regular (Rate 30) CWLP residential electric customer about $2.57 a month to watch a 21-inch color television for an average of three hours a day (approximately 90 hours each month).

0.3 kwh/hr	x	$0.095 per kWh	x	90 hrs/mo.	=	$2.57 per mo.

In addition to helping you determine the approximate cost of operating your various appliances over time, the Appliance Energy Use Chart can help you realize how changes in your energy use habits—such as using appropriately sized stove burners, substituting a microwave oven for a conventional oven, or turning off lights, TVs and other appliances when they aren't needed—can help you control your monthly energy costs.

APPLIANCE ENERGY USE CHART		
Appliance	**kWh Usage**	**Operating Cost (@ 9.5¢ / kWh)**
KITCHEN		
Toaster	0.04 kWh / serving	less than 1¢ / serving
Microwave oven	0.75 kWh / hr	7¢ / hr
Electric frying pan	1.2 kWh / hr	11¢ / hr
Coffee maker	0.2 kWh / pot	2¢ / pot
Range burner (large)	2.4 kWh / hr	23¢ / hr
Range burner (small	1.2 kWh / hr	11¢ / hr
Oven (baking or roasting)	3.2 kWh / hr	30¢ / hr
Oven (broiling)	3.6 kWh / hr	34¢ / hr
Oven (self-cleaning cycle)	10 kWh / clean	95¢ / clean
Refrigerator (pre-2002, manual defrost)	63 kWh / month	$5.99 / month
Refrigerator (pre-2002, frost-free)	168 kWh / month	$15.96 / month
Refrigerator (2002 or newer)	82 kWh / month	$7,79 / month
Deep freezer (frost free)	1835 kWh / month	$17.39 / month
Deep freezer (manual defrost)	135 kWh / month	$12.83 / month
Dishwasher	1 kWh / load	9.5¢ / load
LIVING ROOM/OFFICE/FAMILY ROOM		
Television (21-inch color)	0.3 kWh / hr	3¢ / hr
Stereo	0.15 kWh / hr	1¢ / hr
Computer with monitor (average)	0.09 kWh / hr	1¢ / hr

Mohave Rejoinder Exhibit JTC-1

Computer with monitor (sleep mode)	0.02 kWh / hr	less than 1¢ / hr
Fan	0.2 kWh / hr	2¢ / hr
Room space heater (1500 watt)	1.5 kWh / hr	14¢ / hr
BEDROOM		
Waterbed heater	120 kWh / month	$11.40 / month
Electric blanket	1 kWh / night	9.5¢ / night
BASEMENT/UTILITY ROOM		
Washing machine (excluding water)	0.25 kWh / load	2¢ / load
Clothes dryer (electric)	2.7 kWh / load	35¢ / load
Water heater (for average family of 4)	400 kWh / month	$38.00 / month
Dehumidifier	0.76 kWh / hr	7¢ / hr
Air conditioner (central, 10 SEER)	1.2 kWh / hr / ton	11¢ / hr / ton
Air conditioner (central, 14 SEER)	0.85 kWh / hr / ton	8¢ / hr / ton
MISCELLANEOUS		
Light bulb (100-watt incandescent)	0.1 kWh / hr	4¢ / 4 hrs
Light bulb (25-watt CFL, 100-watt equiv.)	0.025 kWh / hr	1¢ / 4 hrs

Appliance Energy Use

Energy Services Programs

Last updated: 03/26/10

ELECTRIC RATES

MOHAVE ELECTRIC COOPERATIVE, INCORPORATED

1999 Arena Drive
Bullhead City, Arizona 86442
Filed By: J. Tyler Carlson
Title: CEO/General Manager

Effective Date: ____________________

STANDARD OFFER TARIFF

OPTIONAL PREPAID RESIDENTIAL SERVICE SCHEDULE PRS

Availability

In the Cooperative's Certificated Area to standard offer residential customers otherwise served under the Cooperative's Rate Schedule R where the Cooperative's facilities are of adequate capacity and the required phase and suitable voltage and necessary equipment are all in existence on and adjacent to the premises served.

Application and Type of Service

Applicable to qualifying services receiving alternating current, single phase, 60 Hertz, at available secondary voltages where service is provided through a single meter where the Customer elects this optional prepaid service. This rate is not available: (i) to critical (medical necessity), time of use or net metering customers, (ii) for three phase service or (iii) for customers on the Cooperative's Budget Payment Plan. This rate is not applicable to standby, supplementary or resale service.

Monthly Rate

RESIDENTIAL SERVICE PRS	Power Supply		Distribution Charges					Total Rate
			Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Day)			$0.0999	$0.0355	$0.1660	$0.2410	$0.5424	$0.5424
Energy Charge ($/kWh) (Single Phase)								
First 400 kWh per month	$0.095280					$0.001093	$0.001093	$0.096373
Next 600 kWh per month	$0.095280					$0.011093	$0.011093	$0.106373
Over 1,000 kWh per month	$0.095280					$0.021093	$0.021093	$0.116373

Minimum Monthly Charge

The greater of the following, not including any purchased power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge
2. The amount specified in the written contract between the Cooperative and the Customer.

Billing Adjustments and Adders

This rate is subject to all billing adjustments outlined in Schedule A.

Other Charges

Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Rules and Regulations

The Rules and Regulations of the Cooperative as on file with the Arizona Corporation Commission shall apply to Customers provided service under this Service Schedule where not expressly inconsistent with this Service Schedule.

Prepaid Service – Express Conditions

1. Application for Optional Prepaid Service: To receive optional prepaid service the Customer shall:
   a. Be a standard service residential customer (including providing a completed Residential Membership Application) meeting the requirements set forth above under Availability and Application and Type of Service.
   b. Execute a Prepaid Metering Agreement requesting this optional service.
   c. Pay any outstanding balance or pay an agreed upon portion of the outstanding balance and enter into a payment agreement pursuant to Subsection 110-G of the Cooperative's rules and regulations.
   d. Pay the Cooperative's Establishment Fee and an agreed upon prepay amount of not less than $ 40.00 upon subscribing to the prepaid metering option.
   e. Have voice message, e-mail or text message capability in order to receive the messages and low balance alerts. Customers must have at least two reliable methods of receiving messages and low balance alerts, but one can be through a backup contact person.

2. Customer Deposits:
   a. No additional customer deposit will be required. Prepayments are not deemed deposits and are not eligible for interest pursuant to Subsection 102-C 3.d. of the Cooperative's rules and regulations.
   b. Deposits of an existing Customer electing to receive optional prepaid service under this rate schedule shall first be applied against any outstanding bill. Once the remaining deposit is subject to refund pursuant to Subsection 102-C 3.c. of the Cooperative's rules and regulations, any balance will be applied to their prepaid account.

3. Account Information and Billing:
   a. Monthly statements will still be generated for service provided under this optional prepaid service rate schedule covering monthly usage during the billing cycle.
   b. Account information relating to a customer's remaining prepaid balance can be accessed through:

      1) The Cooperative's business offices during normal business hours.
      2) Integrated Voice Recognition (IVR) at 1-877-371-9379 (select Option #1).
      3) On line at www.mohaveelectric.com 24 hours a day.

   c. The Cooperative shall update the remaining prepaid balance at least once each business day, subject to system operational difficulties.
   d. Historical average daily usage information will be available on line or at the Cooperative's business offices. Actual daily usage can only be secured through the Cooperative's business offices.
   e. The billing information made available on line and through the Cooperative's business office shall contain the minimum bill information set forth in Subsection 110-A of the Cooperative's rules and regulations, except that daily billed kWh usage shall only be available through the Cooperative's business offices and no kW demand will be provided.

4. Payments: The residential Customer may make subsequent prepayments as often as desired by making payments in person at the Cooperative's office, or by mailed check; or any time, including after hours, by utilization of the Cooperative's electronic payment system found on the Cooperative's website, or the Cooperative's IVR remote payment system at no cost in fees to the residential Customer. The website and IVR payment systems require a minimum payment of $5.00.

5. Disconnection: Disconnection of prepaid service shall be made when the Customer's prepaid balance reaches zero, except that no disconnection shall occur:
   a. When the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.
   b. Outside normal business hours. Normal business hours are Monday – Friday 8:00 a.m. to 5:00 p.m., excluding Cooperative recognized holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Day after Thanksgiving and Christmas. Usually when falling on Saturday, the Friday before is treated as the holiday and when falling on Sunday, the Monday after is treated as the holiday. The actual dates of all holidays for the calendar year will be posted on the Cooperative's website.

6. Notice: In lieu of written notice of disconnect pursuant to Subsection 111-C of the Cooperative's rules and regulations, the Cooperative shall notify the Customer by electronic mail, where provided, and by interactive voice response phone call at the number provided by the Customer reminding the residential Customer that additional prepaid funds are necessary as the current prepaid amount becomes nearly consumed.

a. Notice shall be generated daily once the Customer's credit balance is less than:
   1) \$25.00 from October 1 to February 28 or 29
   2) \$35.00 from March 1 to June 30
   3) \$50.00 from July 1 to September 30.

7. Re-Establishing Disconnected Service:
   a. Should the residential Customer neglect to make payment prior to disconnection, an additional payment to restore the prepaid balance to not less than \$ 20.00 is necessary to re-establish service. Payment may be made through any of the means described above in paragraph (4). Service will be restored no later than the following business day. For the Customer's safety and to protect property, the Customer must then push the reset button at the meter to re-establish service.
   b. An account will be closed if the disconnected service has not been re-established before the close of the then current monthly billing cycle for the service location, but not less than 10 days after disconnection. The Cooperative (i) will notify the Customer the account is closed in the same manner the Customer received messages and alerts of a low balance and (ii) will also mail a final bill for all unpaid charges to the Customer's last known address on file with the Cooperative. In addition to satisfying paragraph 7a, the Customer must pay an Establishment Fee to re-establish a closed account.

8. Opting In or Out of Prepaid Service:
   a. Any residential Customer of the Cooperative may opt-in or opt-out of prepaid metering service at any time; however the residential customer may change rate options no more than two (2) times in a calendar year, including the initial election of the prepaid metering option.
   b. Any residential Customer who opts-out of this rate and continues service with the Cooperative will be required to:

      1) Pay an Establishment Fee, and
      2) Re-establish credit with the Cooperative as set forth in Subsection 102-E of the Cooperative's rules and regulations; provided, however, utilization of the prepaid metering option for a period of twelve (12) consecutive months without disconnection of service shall have demonstrated the establishment, or re-establishment of satisfactory credit with the Cooperative and shall not be required to post a deposit for continuing service.
   c. Any prepaid balance that remains at the time of transfer to another rate schedule will be applied toward the Establishment Fee, then toward the deposit, then to any balance remaining under a payment agreement and finally, if any balance still remains, as a credit on the first billing.

Contract

If service is requested in the Cooperative's Certificated Area and the provision outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Mohave Electric Cooperative (MEC)
Prepaid Service Agreement

The Prepaid Service Program (the "Plan") is an optional program approved by the Arizona Corporation Commission for MEC's qualifying standard offer, single phase residential customers who desire to alleviate the financial impact of posting a deposit or otherwise securing their service account. It is not available to time-of-use, net metering or critical (medical necessity) customers or for those participating in the Budget Payment Plan. The Plan is designed to give the member more control over their electric usage and more opportunities to reduce their electricity costs. Some of the plan's features that are designed to help members include:

- **No requirement for a security deposit**
- **Smaller, more frequent payments can be made on the account**
- **Avoid late fees**
- **Monitor usage online or by contacting MEC business offices.**

Payments can be made on the Plan utilizing any of MEC's payment systems, including online payments, electronic telephone payments (1-877-371-9379, select Option#1) and payments at our Customer Service office during normal MEC business hours. The Plan offers the members access to their current and historical consumption to assist them in managing their prepaid service. Once a member has registered online, this history can be accessed and their contact information updated with a secured member login at MEC's member website. Alternatively, the Customer can contact the Cooperative's business offices during normal business hours. Daily usage information is only available through MEC's business offices. The information is updated once prior to the start of each business day.

Mohave's Prepaid Service Program is available to qualifying residential customers where Mohave has installed the new AMI digital metering technology and can connect and disconnect your service remotely so no serviceman is needed to be dispatched. However, to <u>protect property and the Customer's safety, the Customer must push a reset button at the meter to re-establish service.</u>

_____ Initial **Electric service is subject to immediate disconnection any time during normal business hours (M-F, 8 a.m. to 5p.m., excluding holidays*) if an account does not have a credit (prepaid) balance,** except where the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast, or other weather conditions as determined by the Arizona Corporation Commission.

- Members can access their balance on the MEC website, telephonically through the MEC integrated voice recognition system (**1-877-371-9379, select Option#1**) or, during normal business hours, by calling MEC business offices. The balance information is updated before the start of each business day.
- The member will receive recorded voice warning notices of low prepaid balances on their account once the balance is less than pre-determined dollar limits that vary seasonally as set forth in its PRS Tariff (currently $25 Oct. - Feb.; $35 March - June; $50 July - Sept.). Warnings will be provided by email, phone or text message to the phone numbers and email addresses designated by the member. These messages will be sent daily until the prepaid balance is exhausted. Other methods of notification may be used with the consent of MEC and the customer.
- The prepaid account will be disconnected at the start of the first business day after the account no longer has a prepaid balance. It is the member's responsibility to make adequate payment to avoid disconnection, and to bring their account back to a prepaid balance of at least $20.00 after disconnection in order to have service restored. Upon the member re-establishing the minimum prepaid balance, service will be restored no later than the following business day, subject to the member pushing the reset button at the meter and operational constraints.
- The account will be closed after disconnection if the minimum prepaid account balance has not been re-established by the end of the billing cycle applicable to the service location, but not less than 10 days after disconnection. If the account is closed MEC's Establishment Fee will also need to be paid to re-establish prepaid service.

Prepaid accounts will be administered in accordance with MEC's Rules and Regulations and Tariffs, approved by the Arizona Corporation Commission, that apply to Prepaid Service (Subsection 102-I and Rate Schedule PRS), as amended from time to time.

- Member authorizes MEC to charge their prepaid account for electric services rendered in accordance with the Rules and Regulations and Tariffs of the Cooperative.
- Member has the ability to access their consumption history as described above and it is their responsibility to utilize the balance information and their consumption in order to maintain a prepaid balance in their account at all times to avoid disconnection of service.
- Member is responsible for maintaining accurate contact information including telephone number, email address and mailing address at all times.
- Member *Holds Harmless MEC, its directors, officers, employee and agents* for damages resulting from disconnecting service in accordance with approved tariffs and rules and regulations of the Cooperative.

* New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Day after Thanksgiving and Christmas. Usually when falling on Saturday, the Friday before is treated as the holiday and when falling on Sunday, the Monday after is treated as the holiday. The current year's holidays are listed on the Cooperative's website.

I have carefully read and I understand the terms within the Mohave Prepaid Service Agreement and understand the difference between prepaid service and standard residential (post paid) service. I am requesting that MEC establish prepaid electric service for my account.

Account Number______________________________

Member Signature______________________________ **Date**______________________

Member Signature______________________________ **Date**______________________

Contact Mailing Address____

Must provide at least two, but no more than four: **Identify order preference (1 – 4)**

(Indicate Name of any person whose number is being provided as a backup)

Contact Email Address(es) ________________________

Contact Telephone Number(s) ________________________

Text Message Number(s) ________________________

ORIGINAL

BEFORE THE ARIZONA CORPORATIO

RECEIVED

2011 SEP 22 P 4: 02

AZ CORP COMMISSION
DOCKET CONTROL

EXHIBIT
MEC-9

COMMISSIONERS
GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. E-01750A-11-0136

CERTIFICATION OF COMPLIANCE WITH PUBLIC NOTICE REQUIREMENTS

Mohave Electric Cooperative, Incorporated ("Mohave" or the "Cooperative") by and through undersigned counsel, hereby files Certification of Compliance with Public Notice Requirements established by Procedural Order dated July 15, 2011. This Certification is supported by the Affidavit of Peggy Gillman and Affidavits of Publication attached hereto.

RESPECTFULLY SUBMITTED this 22nd day of September , 2011.

CURTIS, GOODWIN, SULLIVAN,
UDALL & SCHWAB, P.L.C.

By: ____________________
Michael A. Curtis
William P. Sullivan
Melissa A. Parham
501 East Thomas Road
Phoenix, Arizona 85012-3205
Attorneys for Mohave Electric Cooperative, Incorporated

Arizona Corporation Commission
DOCKETED
SEP 22 2011
DOCKETED BY

102936-1

PROOF OF AND CERTIFICATE OF MAILING

I hereby certify that on this 22nd day of September, 2011, I caused the foregoing document to be served on the Arizona Corporation Commission by delivering the original and thirteen (13) copies of the above to:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Copy of the foregoing emailed
this 22nd day of September, 2011 to:

Dwight Nodes, Administrative Law Judge
dperson@azcc.gov
dbroyles@azcc.gov

Bridget Humphrey, Esq.
bhumphrey@azcc.gov

Margaret Little
mlittle@azcc.gov

Mary Walker

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01750A-11-0136 **AFFIDAVIT OF PEGGY GILLMAN RE PUBLICATION**

State Of Arizona)
) ss
County of Mohave)

Peggy Gillman, being first duly sworn upon her oath deposes and says as follows:

1. I am the Manager of Public Affairs & Energy Services at Mohave Electric Cooperative, Incorporated.
2. In that capacity, I personally oversaw publication of the hearing notice as required by the July 15, 2011 Procedural Order.
3. Mohave Electric Cooperative provided notice of the rate case in the form prescribed in the Procedural Order by:

a) Publishing the notice once in the Mohave Valley Daily News and the Kingman Daily Miner on August 8, 2011 as evidenced by the Affidavits of Publication attached hereto as Exhibit A; and

b) By inserting a copy of the Notice, in the form attached as Exhibit B, in the monthly billing statements commencing August 1, 2011 through August 29, 2011 which encompassed all billing cycles and all consumers of the Cooperative.

DATED this 6TH day of September, 2011.

Peggy Gillman

Peggy Gillman

SUBSCRIBED AND SWORN to before me this 6TH day of September, 2011.

Monika M. Colby

Notary Public

My Commission Expires: June 27, 2014

OFFICIAL SEAL
MONIKA M. COLBY
Notary Public - State of Arizona
MOHAVE COUNTY
My Comm. Expires June 27, 2014

102936-1

EXHIBIT A

Proof of Publication

STATE OF ARIZONA)
County of Mohave) ss

Linda Delano, being first duly sworn, says that during the publication of the notice, as herein mentioned, he/she was and now is the LEGAL CLERK of the **MOHAVE VALLEY DAILY NEWS**. Six times weekly newspaper published on Sunday, Monday, Tuesday, Wednesday, Thursday and Friday of each and every week at the city of Bullhead City, in said county.

That said newspaper was printed and published as aforesaid on the following dates, to-wit:

August 8, 2011

That the **PUBLIC NOTICE OF HEARING OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, FOR A PERMANENT BASE RATE INCREASE (DOCKET NO. E-01750A-11-0136)**
Of which the annex copy is a printed and true copy, was printed and inserted in each and every copy of said newspaper printed and published on the dates aforesaid, and in the body of said newspaper and not in a supplement thereto.

L Delano (CLERK)

Subscribed and sworn to before me this 9 day

of August, 20 11

Laura J. Sullivan
Notary Public

(My commission expires 10·2·2012)

LAURA J SULLIVAN
Notary Public - Arizona
Mohave County
My Comm. Expires Oct 2, 2012

AFFIDAVIT OF PUBLICATION

Kingman Daily Miner

3015 Stockton Hill Road, Kingman, AZ 86401
web: www.kingmandailyminer.com • e-mail: legals@kingmandailyminer.com
Phone (928) 753-6397, ext. 242 • Fax (928) 753-5661
"Serving Kingman since 1882"

STATE OF ARIZONA)
County of Mohave) ss.

I, **Kellie DeCoudres**, being first duly sworn on her oath says:
That she is the Legals Clerk of THE KINGMAN DAILY MINER
An Arizona corporation, which owns and publishes the Miner,
a Daily Newspaper published in the City of Kingman, County of Mohave,
Arizona, that the notice attached hereto, namely,

Legal Notice
Ad. No. 247952

Has, to the personal knowledge of affiant, **8th** day of **August, 2011**
to the **8th** day of **August, 2011** inclusive without change, interruption or omission, amounting in 1 insertion made of the following date;
8/8/2011

By: Kellie DeCoudres
Legal Clerk, **15th** Day of **August, 2011**

State of Arizona

County of Mohave

On this 16 day of August, 2011

Legal Clerk, whom I know personally to be the person who signed the above document and she proved she signed it.

Colleen A. Machado
Notary Public
My Commission Expires August 9, 2015

COLLEEN A. MACHADO
Notary Public - State of Arizona
MOHAVE COUNTY
My Commission Expires
August 9, 2015

EXHIBIT B

PUBLIC NOTICE OF HEARING ON THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, FOR A PERMANENT BASE RATE INCREASE (DOCKET NO. E-01750A-11-0136)

Summary

On March 30, 2011, Mohave Electric Cooperative, Incorporated ("MEC" or "Company"), filed an application with the Arizona Corporation Commission ("Commission") for a permanent gross revenue increase of approximately $2,980,757 million, or approximately 3.79 percent over current revenues, for the provision of electric service within the Company's authorized service area in Arizona. The rate impact on customers would vary based on customer class and individual usage if MEC's proposal were to be adopted.

The Commission's Utilities Division ("Staff") is in the process of auditing and analyzing the application, and has not yet made any recommendations regarding MEC's proposed rate increase. The Commission will determine the appropriate relief to be granted based on the evidence presented by the parties. **THE COMMISSION IS NOT BOUND BY THE PROPOSALS MADE BY MEC, STAFF, OR ANY INTERVENORS; THEREFORE, THE FINAL RATES APPROVED BY THE COMMISSION MAY DIFFER FROM THE RATES REQUESTED BY THE COMPANY OR OTHER PARTIES.**

How You Can View or Obtain a Copy of the Rate Proposal

Copies of the application and proposed rates are available from MEC for customer inspection during regular business hours at its office located at 1999 Arena Drive, Bullhead City, Arizona and at the Commission's Docket Control Center at 1200 West Washington, Phoenix, Arizona, for public inspection during regular business hours and on the Internet via the Commission's website (www.azcc.gov) using the e-Docket function.

Arizona Corporation Commission Public Hearing Information

The Commission will hold a hearing on this matter beginning on **March 19, 2012**, at **10:00 a.m.**, at the Commission's offices, Hearing Room No. 1, 1200 West Washington Street, Phoenix, Arizona. Public comments will be taken on the first day of the hearing. Written public comments may be submitted by mailing a letter referencing Docket No. E-01750A-11-0136 to Arizona Corporation Commission, Consumer Services Section, 1200 West Washington, Phoenix, AZ 85007, or by email. For a form to use and instructions on how to e-mail comments to the Commission, go to http://www.azcc.gov/divisions/utilities/forms/public_comment.pdf. If you require assistance, you may contact the Consumer Services Section at 1-800-222-7000.

About Intervention

The law provides for an open public hearing at which, under appropriate circumstances, interested parties may intervene. Any person or entity entitled by law to intervene and having a direct and substantial interest in the matter will be permitted to intervene. If you wish to intervene, you must file an original and 13 copies of a written motion to intervene with the Commission no later than November 4, 2011, and send a copy of the motion to MEC or its counsel and to all parties of record. **Your motion to intervene must contain the following:**

1. Your name, address, and telephone number, and the name, address, and telephone number of any party upon whom service of documents is to be made, if not yourself;
2. A short statement of your interest in the proceeding (e.g., a customer of MEC, a shareholder of MEC, etc.); and
3. A statement certifying that you have mailed a copy of the motion to intervene to MEC or its counsel and to all parties of record in the case.

The granting of motions to intervene shall be governed by A.A.C. R14-3-105, except that all motions to intervene must be filed on or before **November 4, 2011.** If representation by counsel is required by Rule 31 of the Rules of the Arizona Supreme Court, intervention will be conditioned upon the intervenor obtaining counsel to represent the intervenor. For information about requesting intervention, visit the Commission's website at http://www.azcc.gov/divisions/utilities/forms/interven.pdf. The granting of intervention, among other things, entitles party to present sworn evidence at hearing and to cross-examine other witnesses. However, failure to intervene will not preclude any interested person or entity from appearing at the hearing and providing public comment on the application or from filing written comments in the record of the case.

ADA/Equal Access Information

The Commission does not discriminate on the basis of disability in admission to its public meetings. Persons with a disability may request a reasonable accommodation such as a sign language interpreter, as well as request this document in an alternative format, by contacting the ADA Coordinator, Shaylin Bernal, E-mail Sbernal@azcc.gov, voice phone number 602/542-3931. Requests should be made as early as possible to allow time to arrange the accommodation.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Arizona Corporation Commission
DOCKETED

AUG 06 2009

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EXHIBIT
MEC-10

KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A PERMANENT RATE INCREASE, FOR A DETERMINATION OF THE FAIR VALUE OF THE CORPORATION'S ELECTRIC SYSTEM FOR RATEMAKING PURPOSES, FOR A FINDING OF A JUST AND REASONABLE RATE OF RETURN THEREON, AND FOR APPROVAL OF RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. E-01461A-08-0430

DECISION NO. 71230

OPINION AND ORDER

DATE OF HEARING:	May 20, 2009
PLACE OF HEARING:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
APPEARANCES:	Mr. Russell E. Jones, WATERFALL, ECONOMIDIS, CALDWELL HANSHAW & VILLAMANA, PC, on behalf of Applicant;
	Mr. Nicholas Enoch, ENOCH & LUBIN, PC, on behalf of the International Brotherhood of Electrical Workers Local 1116; and
	Mr. Kevin Torrey, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

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Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

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FINDINGS OF FACT

Background

1. On August 15, 2008, Trico Electric Cooperative, Inc. ("Trico" or "Cooperative") filed an application with the Commission which sought to:

   a. Increase Trico's overall rates to maintain a reliable electrical system and meet financial targets;

   b. Amend the Company's Rules, Regulations and Line Extension Policy ("RR&LEP") to *inter alia*, eliminate the free footage allowance for line extensions;

   c. Modify the Cooperative's Residential Time of Use ("TOU") rates to encourage customers to shift usage to off-peak times and create a reasonable rate of return for the Residential TOU customer class; and

   d. Implement a new Demand Side Management ("DSM") portfolio and collect the costs for its existing programs through a Commission-approved DSM Adjustor mechanism.[1]

2. On September 12, 2008, Staff issued a letter stating that Trico's application met the sufficiency requirements of A.A.C. R14-2-103(B)(7), and classified the Cooperative as a Class A electric utility.

3. By Procedural Order dated September 22, 2008, the matter was set for hearing on May 20, 2009, and various procedural guidelines were established.

4. Freeport-McMoRan Sierrita, Inc. ("Freeport") and the International Brotherhood of Electrical Workers Local 1116 ("IBEW Local 1116") were granted intervention on September 24, 2008 and November 4, 2008, respectively.

5. On December 30, 2008, Trico filed Notice of Filing Affidavits of Publication indicating it had the Public Notice of the hearing published in the *Daily Territorial* on December 4, 2008, and in the *Nogales International* and *Casa Grande Dispatch* on December 5, 2008.

6. On January 13, 2009, Trico filed a Notice of Filing Certificate of Mailing, indicating

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[1] As discussed herein, Trico has been offering seven DSM programs which heretofore had not been approved by the Commission. In its last rate case, the Commission approved a DSM adjustor mechanism, but the mechanism was never activated because the programs had not been approved by the Commission. Trico's existing rates did not include the costs of these programs.

that it mailed to each of its customers a copy of the Public Notice of Hearing on or before December 31, 2008.

7. In response to notification of the rate application, the Commission received seven customer opinions against the rate increase.

8. On January 30, 2009, Trico filed a request to approve a proposed Standard Offer General Service and Time of Use experimental tariff in Docket No. E-00000A-06-0038, a generic docket regarding Smart Metering Requirements of Section 1252 of the Energy Policy Act of 2005.

9. On February 27, 2009, Staff filed the Direct Testimony of Crystal Brown, Jeffrey Pasquinelli, Candrea Allen and Ray Williamson.

10. On February 27, 2009, IBEW 1116 filed the Direct Testimony of Frank Grijalva.

11. On March 2, 2009, Staff filed a Motion for an extension of time to file its rate design testimony to allow the analysis of the tariffs Trico filed in the Smart Metering Docket.

12. By Procedural Order dated March 11, 2009, Staff's Motion for extension of time was granted and a revised schedule for filing testimony established.

13. On March 11, 2009, Staff filed the Direct Testimony on Rate Design and Cost of Service of Prem Bahl.

14. On March 31, 2009, Staff filed the Direct Testimony of Steven Irvine concerning rate design.

15. On April 24, 2009, Trico filed the Rebuttal Testimony of David Hedrick and Vincent Nitido.

16. On May 15, 2009, Staff filed the Surrebuttal Testimony of Candrea Allen and Steve Irvine.

17. On May 18, 2009, a Pre-hearing Conference convened for the purpose of scheduling witnesses. At that time, because there were no disputes, the parties stipulated to the admission of the testimony of Charles Emerson, Marsha Regutto and Michael Searcy for the Cooperative, and Jeffrey Pasquinelli, Prem Bahl, Candrea Allen and Ray Williamson for Staff.

18. The hearing convened as scheduled before a duly authorized Administrative Law Judge on May 20, 2009, at the Commission's Tucson offices. At that time, Mr. Vincent Nitido,

Trico's Chief Executive Officer, Ms. Caroline Gardener, the Cooperative's Finance Manager, and Mr. David Hedrick, its rate case consultant, testified for the Cooperative. Mr. Grijalva testified for the IBEW Local 1116. Mr. Steven Irvine and Ms. Crystal Brown testified for Staff.

19. On June 19, 2009, Trico and Staff filed Closing Briefs.

20. On June 19, 2009, Staff also filed the Supplemental Testimony of Jeffrey Pasquinelli addressing Trico's DSM programs.

Revenue Requirement

21. Trico is a non-profit, member-owned electric distribution cooperative that provides electric distribution service to approximately 38,000 customers located in portions of Pima, Pinal and Santa Cruz Counties, in Arizona.

22. Trico is a full requirements member of Arizona Electric Power Cooperative, Inc. ("AEPCO"), and receives all of its wholesale power from AEPCO.

23. Trico's current rates were set in Decision No. 68073 (August 17, 2005).

24. Trico's application was based on a Test Year ended December 31, 2007.

25. In the ten years since 1997, Trico reports that its number of customers and MWh sales had almost doubled.[2] Ms. Gardiner testified that in the Test Year, the Cooperative's Operating Times Interest Earned Ratio ("OTIER") dropped to 1.05, which is below the minimum of 1.10 required by Trico's lender, the Rural Utility Service ("RUS"), and that the Cooperative's equity fell from 38 percent of total capitalization in 2002 to 25 percent in 2007.[3]

26. Staff's engineering review concludes that Trico is maintaining and operating its electrical system properly; has an acceptable level of system losses, consistent with industry guidelines; is carrying out system improvements, upgrades and new additions in an efficient and reliable manner; and has a satisfactory record of service interruptions in the periods 2007 and 2008.[4]

27. In its application, Trico requested total annual revenue of $80,793,749, an increase of $6,542,728, or 8.81 percent over its proposed adjusted Test Year revenue of $74,251,021.[5] Trico

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[2] Ex A-5, Gardiner Direct at 4.
[3] Id. at 5.
[4] Ex S-4 Williamson Direct.
[5] Trico ultimately adopted Staff's adjustments to Test Year revenue and expenses.

reported an adjusted Original Cost Rate Base ("OCRB") of $154,546,824, which it proposed as its Fair Value Rate Base ("FVRB"). Trico's proposed revenue increase would produce an Operating Income[6] of $11,761,982, or 7.61 percent on FVRB, and an OTIER of 1.68 and a Debt Service Coverage ("DSC") of 2.06.[7]

28. In the Test Year, as adjusted by Staff, Trico had total revenues of $75,477,779, and an adjusted Operating Income of $6,326,553, which resulted in a 4.49 percent rate of return on adjusted OCRB of $140,628,110.

29. Staff recommended total annual revenue of $81,521,496, an increase of $6,043,717, or 8.01 percent over Staff's adjusted Test Year revenue of $75,477,779. Staff's recommendations resulted in Operating Income of $12,370,271, reflecting an 8.80 percent rate of return on Staff's recommend FVRB of $140,628,110, and would produce an OTIER of 1.83 and DSC of 1.93.[8]

30. Staff's recommendations decreased Trico's OCRB by $13,918,714, from $154,546,824 to $140,628,110. Staff eliminated Plant Held For Future Use of $198,972, Construction Work in Progress of $8,148,627 and Working Capital of $5,573,254; increased Accumulated Depreciation by $49,161; and decreased Consumer Deposits by $47,022.[9]

31. With respect to Test Year Revenue and Expenses, Staff recommended: a) revenue and expense annualizations of $970,945 and $723,570, respectively; b) an increase of $255,813 in base cost of power and eliminating $10,755,503 related to the Wholesale Power Cost Adjustor which Trico had added to its base cost of power; c) decreasing operating expenses by $115,828 to eliminate the costs of DSM programs which are to be recovered in a DSM Adjustor; d) decreasing administrative and general expenses by $105,922 to normalize the cost of having two different Chief Executive Officers in the Test Year; e) decreasing payroll by $119,277 to eliminate the costs associated with six part-time employees that were not employed during the Test Year; f) decreasing operating expense to eliminate $20,700 for optional bonuses; g) decreasing operating expenses by $131,462 for advertising and lobbying; h) decreasing property tax expense by $366,736 to reflect

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[6] Throughout the proceeding, the Cooperative and Staff referred to Operating Income as the Operating Margin. Since they are the same thing, we will use operating income.
[7] Ex S-4, Brown Direct, Executive Summary.
[8] *Id.*
[9] *Id.* Schedule CSB-3.

Trico's 2008 property tax bill; and i) decreasing capital credits by $1,986,966 to eliminate the non-cash allocation to Trico by AEPCO.

32. Trico has accepted all of Staff's adjustments to revenue, operating expenses and to rate base, as well as Staff's recommended revenue requirement. In this proceeding, the only disputes between Trico and Staff concerned the appropriate level of the monthly customer charge, the design of the Residential TOU rates, the working of Trico's IS-1 and IS-2 Interruptible Tariffs; and certain language changes and clarifications in Sections 203, Part D and 219 of Trico's proposed RR&LEP.[10]

33. Staff's adjustments to rate base as reflected in the testimony of Ms. Brown, are reasonable and should be adopted. Consequently, Trico's FVRB, which the same as its OCRB, is determined to be $140,628,110.

34. Staff's adjustments to Test Year revenues and expenses are reasonable and should be adopted.

35. The revenue requirement agreed to by the parties allows the Cooperative to meet its financial obligations, as well as build equity, and is fair and reasonable to ratepayers. The Cooperative projections indicate the revenue increase would allow it to reach a 40 percent equity to total capitalization ratio by 2016, and that it will exceed the minimum financial ratios set by the RUS.[11] Consequently, we adopt Staff's recommended revenue requirement in this proceeding.

36. The adopted revenue requirement is an increase of $6,043,717 over adjusted Test Year revenues and results in Operating Income of $12,370,271, and return of 8.8 percent on FVRB.

37. Trico accepted Staff's proposed base wholesale power cost of $0.081638 per kWh sold. Staff's proposed base cost of power incorporates the adjustment factor that was in place at the end of the Test Year, which Staff asserts more accurately reflects the cost of power going forward.[12] Changes in wholesale costs flow through to Trico's customers through its Wholesale Power Cost Adjustment ("WPCA") clause rate. Staff found that Trico's WPCA approved in the last rate case has been working satisfactorily. In the Test Year, the WPCA rate ranged from 1.5 ¢ per kWh to 1.9 ¢ per

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[10] At the hearing Staff and Trico clarified their recommendations concerning the RR&LEP, and resolved their differences.
[11] Ex A-5 Gardiner Direct at 6.
[12] Ex S-7, Pasquinelli Direct at 2.

KWh.[13]

38. We concur with the parties and adopt Staff's proposed base cost of wholesale power.

Customer Charge

39. Trico and Staff do not agree on the appropriate level of the monthly customer charge. Trico's current customer charges, and those proposed by Trico and Staff, as well as the results of the Cost of Service Study ("COSS") are as follows:

	Current	Trico Proposed[14]	Staff Proposed	COSS
Residential	$12.00	$15.00	$13.50	$35.18
Residential TOU	$16.00	$19.00	$16.00	$43.49
GS 1 - Single Phase	$15.00	$18.00	$16.80	$40.49
GS 2 – Single Phase	$15.00	$18.00	$16.80	$93.64
GS 3	$15.00	$18.00	$17.25	$207.97
Water Pumping	$15.00	$18.00	$17.25	$95.87
Irrigation	$15.00	$18.00	$17.25	$131.94
Time of Day ("TOD") Pumping	$15.00	$18.00	$17.25	$177.27
IS-1	$32.00	$36.00	$36.80	$314.94
IS-2	$32.00	$36.00	$36.80	$324.69

Customer service costs are the costs of having service available to the customer before any energy is actually sold. It includes the customer component of distribution line expense, a portion of the transformer expense, the meter and service drop expense, and meter reading and customer records expenses.[15]

40. Trico argues that the COSS is not in dispute and supports a higher customer charge. Trico asserts that its proposed increase in the customer charge can help start de-coupling revenues and energy usage that will help Trico implement DSM programs without disincentives. By increasing the customer charges, Trico argues it will be less dependent upon the sale of energy to recover its fixed distribution costs, and further, that as customer charges are increased, energy

[13] *Id.* at 3.
[14] Ex A-11, Hedrick Rebuttal, DH-4.0. In its rebuttal case, Trico reduced its requested increase for the customer charge.
[15] Ex. A-3, Hedrick Direct at 14.

efficiency and conservation programs will have less of a negative impact on Trico's ability to recover its costs and meet its financial goals. Trico believes that its position as expressed in its rebuttal testimony, which reduced its original proposal, is a reasonable compromise solution.

41. Staff believes that the increase in the customer charge should be limited to 10-15 percent for each customer class to more closely align with the overall increase of 8 percent. Staff does not dispute that Trico's COSS justifies increasing the customer charge, but asserts that designing rates cannot be reduced to a formula, but requires considering multiple factors. Staff believes the goal of cost-based rates must be balanced with principles of gradualism, fairness and encouraging conservation. Staff argues Trico's proposed increase is too great for a one-time increase and does not sufficiently take into consideration other important aspects of rate design.

42. Under the Cooperative's proposed rate design the monthly bill of an average residential customer, using an annual average of 916 kWh per month, would increase $9.82, or 8.40 percent, from $116.89 to $126.71. The median residential customer utilizes 725 kWh per month, and would experience an increase of $8.40, or 8.84 percent, from $95.06 to $103.46 per month.[16]

43. Under Staff's proposed rate design the monthly bill of an average residential customer, using 916 kWh per month, would increase $10.48, or 8.96 percent, from $116.89 to $127.37. The median residential bill would increase $8.60, or 9.05 percent, from $95.06 to $103.66.[17]

44. The dollar difference between Trico's and Staff's proposed rates is de minimis. After considering the entire record, we adopt the Cooperative's proposed customer charges and rate design.[18] Although Staff's recommendations are based on sound principles and are not unreasonable, considering the effect on all customer classes, including the proposed Residential TOU Class discussed below, we find that the Cooperative's proposal best distributes the incremental revenue increase, and moves the customer charge closer to the cost of service.

Residential Time of Use Tariff

45. Trico presented evidence that its current Residential TOU rate has resulted in an

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[16] Trico Brief. Exhibit 6.

[17] Ex S-5, Irvine Direct, H-4.0. Staff's analysis in its direct testimony did not include the DSM adjustor as Staff had not yet made its recommendations concerning DSM programs.

[18] Trico did not propose any changes to its service charges or fees.

annual loss to Trico of between $800,000 and $1,000,000 since 2007.[19] Mr. Hedrick testified that the Cooperative's existing Residential TOU Tariff is ineffectual because it does not send the appropriate price signal that should encourage customers to reduce consumption during on-peak periods. As currently structured, the Residential TOU rates allow customers to reduce their bills without modifying their behavior.

46. On February 6, 2008, Trico filed a request with the Commission to freeze the existing Residential TOU tariff so that additional customers could not sign up for this rate. The Commission approved Trico's request to freeze the existing Residential TOU tariff in Decision No. 70212 (March 20, 2008). Decision No. 70212 acknowledged that in 2007, customers were migrating to the TOU tariff and saving approximately $40 per month without shifting any on-peak load, and the effect on Trico's revenues was further exacerbated by an increase of 20 percent in AEPCO's demand rate per KW since 2004.[20]

47. Trico had originally proposed a phase-in of its proposed Residential TOU rates because it was proposing a significant increase for this customer class. The current TOU rate provides for 8 on-peak hours during Monday through Friday in the summer and no on-peak hours on weekends. Trico presented an analysis that shows that AEPCO's Coincidental Peak fell on three weekend days for each of the years 2006, 2007 and four weekend days in 2008. In light of this evidence, Trico proposed the Residential TOU Tariff to reduce on-peak summer hours from 8 to 6 hours, but to include 6 on-peak hours on weekends, which would result in approximately the same number of on-peak summer hours as in the current tariff.

48. Trico asserts that Staff's Proposed TOU rates will produce a negative annual return or loss of $485,006, which results in Trico's other customer classes subsidizing the Residential TOU class. Trico states that its compromise rate design (i.e. as expressed in its rebuttal case, which reduced its original proposed customer charge from $21.00 to $19.00 per month) provides no positive or negative return to Trico from this class. Trico asserts that imposing a negative return on this rate class would make the Residential TOU rate less effective and hinder its ability to regain financial

[19] Ex A-3 Hedrick Direct at 15; Transcript of May 20, 2009 Hearing ("Tr") at 58.
[20] Decision No. 70212 at Findings of Fact No. 7.

strength and meet its required OTIER. Trico argues that it is critical to earn an OTIER of at least 1.15 in 2009 in order to meet its mortgage requirements. Given its OTIER of 1.04 and 1.05 in the last two years, Trico states that it cannot afford to have a rate class with a negative return.

49. Staff agrees that Trico's existing Residential TOU rate has been ineffective and Staff does not dispute the results of the COSS.[21] Staff states that it designed a Residential TOU rate schedule that keeps the monthly service charge proportionately aligned with other customer classes and raises the energy charges to provide a substantial increase to revenues without imposing rate shock. Staff asserts that its design incorporates a clear price signal through its rate differential between on- and off-peak hours and designates flexible peak days and hours that allow customers to exercise control over their load-shifting. Staff recognizes the higher costs to serve TOU customers, but recommends no increase to the monthly charge for this rate class because Staff believes the existing charge of $16.00 per month compared with Staff's proposed $13.50 for the standard customer, already reflects the difference.[22]

50. Staff agrees with the Cooperative that there has been "some" under-recovery from the Residential TOU class and proposes to boost revenue through higher energy charges. Staff argues that included in its proposed energy charges is a clear price differential between the on-peak and off-peak hours that sends the appropriate price signal for customers to shift load to off-peak hours. Staff states its proposed rate increase for this customer class is designed to provide an equitable return and encourage conservation, but is tempered with gradualism to avoid rate shock. For these reasons, Staff did not recommend a phase-in of the new Residential TOU rates.

51. Staff also recommends not including weekends in on-peak hours. Staff states it recognizes that coincident peaks have occurred on weekends during the past few years, but does not find the Cooperative's reasoning sufficiently compelling. Staff states that it is willing to reconsider Trico's proposal if it could provide more detailed information.[23] Staff states that specific hourly load and cost data would be needed for the evaluation of a change to on- and off-peak hours in any case.[24]

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[21] Ex S-3, Bahl Direct at 7; Tr at 106.
[22] Ex S-5 Irvine Direct, SPI-1 at 1.
[23] Tr at 112-113.
[24] Id.

Staff asserts that having on-peak weekend hours may be unduly burdensome to ratepayers who have expressed concerns in the past that it would be difficult to avoid on-peak hours during weekends.[25] Staff believes that Trico's proposal to reduce the number of on-peak hours for the other days does not sufficiently address the issue.

52. Trico's current TOU Tariff is ineffectual and detrimental to the financial condition of the Cooperative. We believe that having effective TOU tariffs that encourage customers to shift load to off-peak hours is important. We are concerned however, about the Residential TOU Tariff in this case producing a negative return for the class. Customers who are not able to shift load for various reasons should not have to subsidize the TOU Class. At this point, we need more information to evaluate the Cooperative's proposal to include on-peak hours on weekends, and we note that other utilities typically do not include on-peak times during weekends. The effect on ratepayers is unknown and we do not want to discourage them from taking TOU rates solely because of the weekend on-peak hours. Consequently, we direct Trico to file for Commission approval a Residential TOU Tariff that results in a neutral return on the Cooperative from the TOU class.

Interruptible Tariff

53. The parties also disagree about the design of the Interruptible Rate Tariff.

54. Trico proposes to retain the existing tariff language as follows:

> In the event the customer has metered demand at the time of AEPCO peak more than twice in a calendar year, the Cooperative <u>may</u> disconnect the controlling device and discontinue interruptible Service. (Emphasis added).

55. Staff proposed to change the "may" to "will." Under Staff's recommendation, a customer would be removed from the IS-1 or IS-2 tariff if it overrides Trico's interruption at the time of the AEPCO co-incident peak more than twice within a 12 month period. Staff argues that the interruptible tariffs and override penalties are not solely about recovering costs. Staff believes that the Cooperative's position on the interruptible tariff ignores DSM program goals, including reducing consumption, and disregards that the additional revenue from the penalty is offset by the reduced revenues collected under the tariffs during the non-peak periods. Staff states it is therefore uncertain

[25] Decision No. 70212 at Findings of Fact No. 4.

if there is full cost recovery. Staff argues there must be more to an override penalty than recovering costs. Staff is concerned that when customers are allowed to repeatedly override interruptions, it defeats the purpose of the tariff, and without an explicit, substantial consequence, the tariff is ineffective and the Cooperative stands to lose the benefits.

56. Trico asserts that the rates for the IS-1 and IS-2 Class provide Trico with a high rate of return. If a customer on these tariffs override a Trico interruption during an AEPCO peak the customer must pay Trico $29.50 per kW as a demand charge for each kW Trico is charged by AEPCO as a result of the override.[26]

57. Trico argues that the penalty demand charge is a strong disincentive for customers to override the call for interruption and the increased rate covers any added expense Trico has to pay AEPCO due to a customer's override decision. Trico states that any load that is reduced helps benefit all customers on Trico's system due to Trico's peak demand billing from AECPO, and that to automatically remove customers from this rate class due to small overrides is detrimental to all customers on the system. Trico argues that it is in the best interest of its customers to give Trico the discretion as to whether a customer should be removed from this class.

58. The testimony at the Hearing was that the majority of customers' overrides are attributed to a small part of the customer's overall load.[27] There was no indication that there is a wholesale abuse of the override provision. If a customer is removed from the tariff, it will no longer have incentive to curtail its load during peaks, and Trico will lose the benefit that the tariff provides. In the absence of evidence that the tariff is not working as intended, we will leave the language as it currently exists.

TOD Tariff

59. Trico has accepted Staff's recommendation to revert the proposed Time-of-Day Pumping Service ("TOD-P") rate structure back to its existing terms and conditions. Trico had proposed to define the on-peak demand period only as usage metered during system coincident peaks (coincident with AEPCO's peak), rather than as usage during clearly specified hours. Staff states that

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[26] The AEPCO cost charged to Trico is approximately $22 a kW. Tr at 46.
[27] Tr. at 48, 64-65.

not having previously identified peak hours raises concerns about the customer's ability to control the appropriate shifting of load at the proper times. Staff's proposal defines peak usage the same as in a traditional TOU rate, which it believes allows customers to make informed decisions regarding shifting load.[28]

60. Staff's approach (which maintains the existing language) to TOD is reasonable, and easier for customers to understand and apply, and should be adopted.

Experimental General Services TOU Tariff

61. Staff also recommends approval of Trico's proposed experimental General Service – Time-of-Use ("GS-TOU") rate. This rate defines on-peak demand as usage metered during system coincident peaks, rather than as use during clearly identified hours. Staff believes the introduction of this rate as an experimental rate is an appropriate method to determine customer acceptance and effectiveness of an identified on-peak period.[29]

62. We find that Staff's recommendation concerning the experimental GS-TOU Tariff is reasonable and should be adopted. As an experimental tariff, Trico will be able to collect data to determine if a different method of defining peak times can be effective.

Rules, Regulations and Line Extension Policies

63. Staff and Trico agree that the RR&LEPs, as proposed by the Cooperative, and modified by the Direct Testimony of Staff witness Allen, and in the Rebuttal Testimony of Cooperative witness Hedrick,[30] should be adopted.

64. Staff agrees with Trico's proposal to eliminate free footage for line extensions and believes the change will improve the Cooperative's ability to recover the costs associated with the anticipated continuation of above-average growth in the Trico's service area. Staff states that to be equitable to those potential customers who may have already made commitments based on the previous free footage allowance, Staff recommends that any customer who was given a line extension estimate or quote in the twelve months prior to an order in this matter be exempt from the policy and

[28] Ultimately, there was no dispute among the parties about the TOD Tariff, however, it is included herein to clarify the resolution of the issue.
[29] Ex S-5 Irvine Direct at 4.
[30] Staff Brief at 8. A copy of the proposed revised RR&LEP is attached to Trico's Brief as Exhibit A.

be granted the free footage per the previous policy.

65. The parties' resolution of the proposed changes to the RR&LEP is reasonable, and the modified RR&LEP, as set forth in the Cooperative's Brief, should be approved. Trico believes the elimination of the free footage for line extensions will significantly reduce its need to borrow in the future, which will positively affect its equity capitalization ratio. The elimination of the free footage for line extensions, as conditioned by Staff's recommendations, is fair and equitable and conforms to recent Commission decisions for other utilities.

DSM Programs

66. Decision No. 68073 authorized Trico to employ a DSM adjustor mechanism to recover the costs of pre-approved DSM programs. Trico has not to date, implemented the mechanism because it had not obtained Commission approval for its DSM programs.

67. Trico requested the approval of several DSM programs as part of its rate application, but at the time of the hearing, Staff was not yet prepared to make any recommendations.[31] Pursuant to the agreement of the parties and as approved by the Administrative Law Judge, Staff filed the post-hearing Supplemental Testimony of Mr. Pasquinelli, which supports approval of Trico's proposed DSM programs, with conditions.

68. Trico proposed the following DSM programs, which are already in operation, but which have not yet been approved by the Commission:

a. Member Service Representative ("MSR") Energy Training Workshop; a seven hour training session designed to educate Trico's MSRs in advanced energy savings techniques, which would enable them to better assist members in using energy more efficiently. The MSRs are trained to conduct telephonic surveys at the end of which they will be able to make recommendations on energy conservation to members. Trico reports the cost for this program is $78,430.

b. Conservation Workshop Program; Trico representatives meet with homeowners associations, apartment complex residents or any community group to lead a

[31] Ex A-7 Regrutto Direct at 4; Ex S-7 Pasquinelli Direct at 4.

workshop on energy conservation techniques. Trico reports a total cost of $2,000.

c. Classroom Connection; Trico representatives educate elementary school students on the overall concept of conserving energy as well as on methods to conserve in their own homes. Trico reports a cost of $2,548.

d. Residential Home Energy Audits; under this program, Trico members identify where their homes use the most energy and receive information on how to reduce energy consumption. Trico MSRs help the members through a "self-audit" telephonic survey, and can schedule an on-site energy audit. The auditor can make recommendations that will result in a more energy efficient home. Trico reports a cost for this program of $1,675.

e. Non-Residential Energy Audits; under this program, a survey, load profile analysis and review of historical usage are performed upon the request of commercial and industrial customers and compiled into a comprehensive report. Trico reports a cost of $5,000.

f. Operation Cool Shade; Trico would purchase desert-adapted trees from local growers and offer them to members at discounted prices to promote energy conservation through the planting of low-water use shade trees in key locations around a home or business. Trico reports a cost of $22,075 for this program.

g. Pima County Weatherization; offered by Pima County, this program assists low-income residents to reduce energy use and lower utility bills through the implementation of year-round weatherization methods. It is provided at no cost to eligible Trico customers. Trico provided $4,100 in funding for this program in its service area.

69. Regarding Trico's proposed DSM programs, Staff recommends as follows:

a. <u>MSR Training</u> -- Staff does not recommend Commission approval as a separate program at this time, because it is difficult to measure results of education conservation programs. Staff believes the training is valuable, however, and recommends this training program be done as part of the Energy Audit Program.

b. Conservation Workshop Program – Because Staff believes that it is difficult to measure results of educational conservation programs, Staff does not recommend Commission approval as a separate program at this time, however, as with the MSR Energy Training Workshop, Staff recommends the Conservation Workshop Program be done as part of the Energy Audit Program,

c. Classroom Connection - As with the first two programs, Staff believes that measuring results of educational conservation programs is difficult because the goal of these programs is to change behavior. Staff believes that while standard economic analysis may not be appropriate, its effectiveness must still be determined. Staff recommends that Trico establish thorough monitoring and evaluation measures, including surveys and the collection of participant data, to verify the program's effects.

d. Residential Home Energy Audits – Staff recommends that the Residential and Non-Residential Home Energy Audits Programs be consolidated into one Energy Audit Program and approved with conditions (as set forth below).

e. Non-Residential Energy Audit Program – Staff recommends the Non-Residential Energy Audit and Residential Home Energy Audit Programs be consolidated into one Energy Audit Program and be approved with the following conditions: (1) the Conservation Workshops and MSR Training be incorporated in the Energy Audit Program; (2) comprehensive monitoring and evaluation techniques be developed and employed; and (3) to be sure that DSM and conservation funds are well spent, the Energy Audit Programs should be approved as a two-year pilot program, at the end of which period, Trico would submit an all-inclusive report detailing the results of its energy audits.

f. Operation Cool Shade Tree-Planting Program – Staff's analysis of this program shows a benefit/cost ratio of 2.9, which indicates that the benefits are greater than the costs. Staff recommends that the Cool Shade Tree Program be approved with the following conditions: the program should provide participants with information emphasizing the energy savings that result from planting trees to shade buildings; the tree species must be appropriate for the area; the direction the trees face must be appropriate for shading the building; the distance between the tree and the building must be appropriate for maximum benefit; south wall plantings must be deciduous trees to allow for winter heating effects; information must be made available to homeowners about safely pruning trees to decrease winter shading; program participants must be provided with information regarding tree maintenance and the removal of ground debris to reduce fire danger; members are provided up to four trees per home or business if it can be determined that there are enough resources to provide the additional trees without creating a shortage for other participants; the monitoring and evaluation process include the development of data concerning tree maintenance costs, tree mortality and kW/KWh savings; and the program be reported in the Cooperative's DSM reports.

g. Pima County Weatherization – Staff's analysis shows a benefit/cost ratio of 0.97, indicating that the benefits are nearly equal to the costs. Staff's analysis does not include the benefits of reduced environmental effects, however, and Staff believes that if these societal benefits were quantified and incorporated into Staff's analysis, the benefit/cost ratio would be greater than one. Staff recommends approval of this program.

70. Staff also recommends that Trico begin to study and analyze a way to add a Compact Fluorescent Lamp ("CFL") program to its DSM portfolio, as Staff's experience is that CFLs are among the most cost-effective methodologies for conservation or DSM.

71. We approve Trico's proposed DSM programs, as conditioned by Staff's recommendations. We believe they are a reasonable response in the effort to reduce customer demand for energy consumption. We believe, however, that Trico should also study additional DSM programs, in particular the CFL program suggested by Staff, but also other ways to effectively and efficiently reduce demand. Trico can apply for Commission approval of new DSM programs at any time. As it has done in the past, Trico can offer new DSM programs pending Commission approval with the understanding that the costs of such programs will not be collected from ratepayers unless and until the Commission approves the program.

72. Based on the costs of Trico's DSM programs of $115,828, and sales of 605,300 MWh, Trico's initial DSM Adjustor rate is determined to be 0.0191356 ¢ per kWh.[32] Based on annual average usage of 916 kWh, the DSM adjustor rate would add $0.175 to the monthly residential bill.

CONCLUSIONS OF LAW

1. Trico is a public service corporation pursuant to Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over Trico and the subject matter of the application.

3. Notice of the proceeding was provided in conformance with law.

4. The rates, charges and conditions of service approved herein are just and reasonable and in the public interest.

5. It is in the public interest to approve Trico's DSM programs as conditioned by Staff's recommendations in the Supplemental Testimony of Jeffrey Pasquinelli dated June 19, 2009.

ORDER

IT IS THEREFORE ORDERED that Trico Electric Cooperative, Inc. is hereby authorized and directed to file with the Commission, within 15 days of the effective date of this Decision, revised schedules of rates and charges consistent with the discussion herein, and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the rates and charges approved herein shall be effective for all usage on and after August 1, 2009.

IT IS THEREFORE ORDERED that Trico Electric Cooperative, Inc. shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert in a form acceptable to Staff, included in its next regularly scheduled billing.

IT IS FURTHER ORDERED that Trico Electric Cooperative, Inc. shall recover the costs of Commission-approved DSM costs through its DSM Adjustor.

IT IS FURTHER ORDERED that Commission-approved DSM costs should be assessed to all

[32] Ex S-7, Pasquinelli Direct at 4.

Trico Electric Cooperative, Inc's customers as a clearly labeled single line item per kWh charge on the customer bills.

IT IS FURTHER ORDERED that Trico Electric Cooperative, Inc. shall file its report on DSM program expenses semi-annually on April 1st for the period July through December and October 1st for the period January through June.

IT IS FURTHER ORDERED that Trico Electric Cooperative, Inc.'s initial DSM adjustor rate is $0.000191356 per kWh, until further Order of the Commission.

IT IS FURTHER ORDERED that Trico Electric Cooperative, Inc.'s proposed changes to its Rules, Regulations and Line Extension Policies, as agreed to amongst the parties and set forth in Exhibit 1 to Trico Electric Cooperative, Inc.'s Closing Brief, is approved.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 6TH day of AUGUST, 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT

DISSENT

SERVICE LIST FOR: TRICO ELECTRIC COOPERATIVE, INC.

DOCKET NO.: E-01461A-08-0430

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UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.14: Please set forth all data (by category or type) the Commission Staff now expects MEC to maintain to support purchased power costs recovered through its purchase power adjustor.

EXHIBIT
MEC-11

<u>RESPONSE</u>:

MEC would continue to file its monthly purchased power adjustor report including the following information:

- A cover letter that:
  - Is addressed to the Commission's Compliance Section;
  - The month for which the monthly report is being filed;
  - The Decision No(s). which ordered the monthly report and/or information required to be included; and
  - The name and contact information of the employee who can be contacted regarding the information provided in the report.

- Bank Balance Report for the month indicated in the cover letter including:
  - The beginning bank balance which should equal the previous month's ending bank balance. (Any revisions to the ending or beginning bank balance of a particular month should be reflected in the previous month's or succeeding month's bank balance report.);
  - Jurisdictional kWh sales by customer class;
  - Actual cost of purchased power (including transmission costs) supported by invoices. Copies of all invoices for power purchased and transmission should be included. (Invoices for costs for services other than purchased power that MEC intends to recover through the purchase power adjustor.);
  - Unit cost of purchased power;
  - Authorized base cost of purchased power;
  - Authorized purchase power adjustor rate;
  - Incremental difference between the actual and the authorized cost of purchased power;
  - Net changes to the bank balance;
  - Adjustments to the bank balance. (Any and all adjustments to the bank balance should be documented as a sub-report to the Bank Balance Report which should include a detailed explanation of any adjustments and the itemized amounts including the total amount of the adjustment(s). This sub-report should be titled *Adjustments to Bank Balance* and should specify the month for which the adjustment(s) are being made.); and

  - Ending bank balance which should be the sum of the beginning bank balance, net changes to the bank balance, and adjustments to the bank balance.

- Revised monthly purchased power adjustor reports:
  - Should MEC find it necessary to file revised monthly reports, the cover letter of the revised filing should clearly state that the filing is a revised version of the previously filed report. In addition, the cover letter should indicate what information is being revised. Further, the revised information should be distinguished from the information not revised (e.g. highlight, different font, bolding, etc). The revised report should be filed in the same manner as the original report.

Because legal fees, consulting fees, lobbying fees, DSM costs or any other fees/charges/costs not approved to be recovered through the purchased power adjustor, invoices for these activities should not be included in the monthly purchased power adjustor reports.

RESPONDENT: Candrea Allen, Public Utilities Analyst II

UTILITIES DIVISION STAFF'S RESPONSES TO MOHAVE ELECTRIC COOPERATIVE, INC.'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION DOCKET NO. E-01750A-11-0136 FEBRUARY 17, 2012

MWS-2.18: Please identify the date (or the approximate date) Staff decided to seek a prudence review of power purchases made by MEC and provide any Information that supports or contradicts your response.

RESPONSE:

Staff had discussed the need for such a prudence review of MEC during the Sulphur Springs Valley Electric Cooperative rate case. Most often, Staff conducts the prudence review in conjunction with a rate case proceeding. MEC filed its rate application on March 30, 2011.

RESPONDENT: **Candrea Allen, Public Utilities Analyst II**

EXHIBIT
tabbies
MEC-12

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	)	DOCKET NO. E-01750A-11-0136

DIRECT

TESTIMONY

OF

MARGARET (TOBY) LITTLE

ELECTRIC ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

EXHIBIT
S-1

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EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Margaret (Toby) Little's testimony makes recommendations regarding the Arizona Corporation Commission ("Commission" or "ACC") Utilities Division Staff's ("Staff") engineering evaluation of Mohave Electric Cooperative's ("MEC," "Mohave Electric" or "Cooperative") Application for a Determination of the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and to Approve Rates Designed to Develop Such Return ("Application") filed with the Commission in Docket No. E-01750A-11-0136. In conjunction with Staff's engineering evaluation, Staff gives an account of its inspection of MEC's distribution system, of MEC's current operations and maintenance, and of MEC's future plans for its electric system. Staff has the following conclusions and recommendations:

1. It is Staff's conclusion that Mohave Electric:

   A. is operating and maintaining its electrical system properly,

   B. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate.

   C. has an acceptable level of system losses, consistent with the industry guidelines, and

   D. has a satisfactory record of service interruptions in the historic period from 2001 thru 2010, reflecting satisfactory quality of service.

2. Staff recommends that:

   A. Mohave Electric should continue with planned system improvements and additions as provided for in the 2008-2011 Construction Work Plan.

   B. Mohave Electric should continue with its plans in utilizing the SMART grid grant and with its REST plan.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Margaret (Toby) Little. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I received both my Bachelors and Masters Degrees in Electrical Engineering from New Mexico State University. I graduated with my Bachelors Degree in July 1972, and received my Masters Degree in January 1979. My Masters Program at New Mexico State University was in Electric Utility Management. I received my Professional Engineering ("P.E.") License in the state of California in 1980.

Q. Please describe your pertinent work experience.

A. I worked at the Arizona Corporation Commission from September 2010 to February 2011 as a Utilities Consultant, and since February 2011 I have been employed at the Commission as an Electric Utilities Engineer. During this time I have performed engineering analyses for financing cases, helped coordinate the Sixth Biennial Transmission Assessment, reviewed utilities' load curtailment plans and summer preparedness plans, and conducted various other engineering analyses. From 1983 through 1987 I was the Supervisor of System Planning for Anchorage Municipal Light and Power, the second largest utility in Alaska. There I had overall responsibility for distribution, transmission and resource planning for the utility and supervised six electrical engineers. From 1979 through 1982 and 1987 through 1988 I worked for R.W. Beck and Associates, a nationally recognized engineering firm. There I performed many types of engineering analyses involving resource and transmission planning and worked on the engineer's reports for the financing of a major generation facility in northern California. Prior to that, I worked in the System Planning Sections of San Diego Gas and Electric Company and Hawaiian Electric Company, where I had responsibility for short and long range distribution planning.

Q. As part of your assigned duties at the Commission, did you perform Staff's engineering analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

PURPOSE OF TESTIMONY

Q. What is the purpose of your prefiled testimony?

A. The purpose of my testimony is to discuss Staff's engineering evaluation of the Mohave Electric Cooperative's ("MEC," "Mohave Electric" or "Cooperative") system operations and planning, and to present the results of this review. Mohave Electric's current rates and charges were approved by Commission Decision No. 57172 dated November 29, 2009.

ENGINEERING EVALUATION

Q. Did you perform an engineering evaluation of MEC's electrical system?

A. Yes, I did. In response to Mohave Electric's rate filing, I inspected the Cooperative's distribution system facilities on July 18 and 19, 2011, and discussed with MEC's officials certain elements of its rate filing and the Cooperative's Construction Work Plan ("CWP") 2008-2011. I also relied on the responses to Staff's data requests (both written and verbal) received from the Cooperative's officials.

Q. Will you please enumerate the highlights of your inspection of Mohave Electric's electric system?

A. Yes, I will. The following provides an account of my inspection of MEC's electrical system and my analysis of the data provided both in the initial filing and in response to data requests.

I visited the Cooperative's offices on July 18 and 19, 2011, and met with Ms. Peggy Gilman, Manager of Public Affairs and Energy Services, Mr. Arden Lauxman, Chief Financial Officer, and Mr. Neil Garney, Operations Supervisor. On July 18 we toured the western service area and I inspected various substations and distribution system elements; on July 19 we visited the eastern service area and I inspected various elements of that part of the electric system.

A. <u>Mohave Electric's Service Area</u>

The Cooperative has two separate service areas totalling nearly 1,300 square miles across three counties. The western service area is bordered on the west by the Colorado River, and roughly follows State Highway 95 from State Highway 68 in the north to Interstate 40 in the south and including Bullhead City. The eastern service area begins east of Kingman and follows State Road 93 south to the general area of Wikieup. It also follows Route 66 to the north into Coconino and Yavapai Counties. MEC serves the communities of Bullhead City, Fort Mohave, Mohave Valley and Golden Shores in the west and Wikieup, Hackberry and Peach Springs in the east. MEC's service territory includes very sparsely populated areas, rural communities and larger towns.

B. Electric System Description

MEC is a distribution cooperative providing electric service to its members. MEC has no generating capacity of its own and is a Partial Requirements Member of Arizona Electric Power Cooperative, Inc. ("AEPCO"). Power is delivered at Riviera, Topock, and Bullhead Substations to the western service territory and at Bill Williams, Kingman, and Round Valley Substations to the eastern service territory.

C. Electric System Characteristics

As of December 31, 2010, MEC provided electric power distribution service to 38,718 metered customers. Of these, 34,735 were residential customers, 23 were irrigation customers, 3,940 were Commercial and Industrial Customers 1000 kilo Volt Amperes ("kVA") or less, 3 were Commercial and Industrial Customers 1000 kVA or more, 16 were Public Street and Highway Lighting Customers, and one was a Sales for Resale Customer.

Mohave's system peak load increased from 148.7 Megawatts ("MW") in 2001 to 200.7 MW in 2010, showing an average annual increase of 3.89 percent over this time period. However, over the most recent five year period, (2005-2010), the average annual increase in peak load has been 0.87 percent, which Staff concludes is primarily due to poor economic conditions in the state as a whole and in particular the part of the state served by MEC.

The average number of services, including all classes of customers, increased from 30,830 in 2001 to 38,718 in 2010, indicating an average increase of 2.84 percent per year. The average annual growth in number of customers over the most recent five year period, (2005-2010), has been 1.01 percent, again reflecting the economic climate in the state. The peak load growth seems reasonable for the rural territory served by Mohave Electric.

MEC has 1,512 miles of energized lines, including 1,055 miles of overhead distribution lines[1], 349 miles of underground distribution cable[2] and 108 miles of sub-transmission lines[3]. The Cooperative's service territory is located within Western Area Power Administration's ("WAPA") Load Control Area[4].

D. Annual System Losses

Mohave Electric's annual historic system losses are listed below.

2005	4.08%
2006	4.05%
2007	4.16%
2008	4.92%
2009	4.55%
2010	3.03%

[1] 25 kV and below
[2] 25 kV and below
[3] 69 kV
[4] An electrical system bounded by interconnection metering and telemetry, capable of controlling generation to balance supply and demand, maintain interchange schedules with other control areas, and contribute to the frequency regulation of the interconnection.

These losses average 4.13 percent per year for the most recent six year period, (2005-2010), and are well below the reasonable limits in the guidelines provided by the American Public Power Association's Distribution System Loss Evaluation Manual applicable to electrical systems such as that of the Cooperative's. Typical distribution system loss values indicated in the said Manual range between 6 percent for urban systems to 10 percent for rural systems.

E. <u>Quality Of Service</u>

The outages that occur in a utility's system stem from a variety of causes and are an indicator of the quality of service to customers. Some of these causes are storm –related; others are relative to switching surges, equipment failure and planned outages. The historical data relative to Mohave's distribution system outages is shown in the following table.

Year	**Avg. Customer Outage Hours per Year**
2005	2.94
2006	6.94
2007	1.69
2008	2.43
2009	1.99
2010	2.34

The average over the past five year period for MEC has been 3.67 customer outage hours per year. According to the Rural Utilities Service ("RUS") Bulletin 161-5, average customer outage hours per year of five or under are acceptable. The information indicated in the above table shows that the Cooperative's service quality in terms of reliability exceeds the RUS standard. In answer to a question from Staff about the unusually high outage hours in 2006, MEC indicated that there was an especially severe monsoon storm in the summer of 2006 that caused the loss of both primary and back-up distribution feeds to several substations in the west service area. Crews were able to restore power in a reasonable time period given the extreme circumstances.

F. **Distribution System Inspection**

During my inspection of Mohave Electric's distribution system, it was noted that several system improvements and system upgrades had been made by the Cooperative in accordance with the Cooperative's Construction Work Plan 2008-2011. Several other upgrades and improvements listed in the CWP are planned to be constructed and placed in service in the near future.

In 2010, Mohave Electric completed the Natural Corrals Substation north of Wikieup in the east service area. This substation had been determined to be needed for voltage regulation at the south end of the service area. Voltage regulators in the area will remain as back-up in case of the loss of the substation. The new substation was inspected as part of the visit to the east service area.

MEC has completed upgrades to two distribution circuits, (Davis Circuit 1, (Phase I), completed in 2008; and Swam Circuit 3, completed in 2011), and one section of transmission, (Riviera to Lipan, completed in 2008) in the past few years to increase reliability and to meet additional demand. The current CWP provides for upgrading several other distribution circuits, (Hualapai Circuit 2, anticipated 2013; Hualapai Circuit 3, anticipated 2013; Davis Circuit 1, (Phase II), anticipated 2014;

Airport Circuit 1, anticipated 2014; WV Circuit 2, anticipated 2012; and Hualapai Circuit 2, anticipated 2012), also to increase reliability and to meet additional demand in the areas served by those feeders. In 2008 a second recloser was added at Davis Substation, creating Davis Circuit 2, and the transformer was upgraded at that substation, also in 2008.

In general, the MEC electric system appears to be well planned and maintained. No deficiencies or obvious problems were observed during the inspection tour. It was also noted that the substations are properly maintained, with safety-related equipment installed and 'Danger' signs installed on the fence around the substations. No oil leakage at the substation transformers was detected.

Mohave Electric has an ongoing plan to test wooden poles and replace those that have reached the end of their useful lives. According to MEC staff, the wooden poles in their service territory seem to have a longer than expected life span, perhaps due to the service territory's extremely dry climate.

Mohave has an aggressive plan for tree trimming; no areas needing trimming were observed on the inspection trip.

G. SMART Grid Grant And REST Plan

A SMART grid grant was received from United States Department of Energy ("DOE") in 2010. Mohave is a sub-grantee of DOE Grant Number DE-OE-0000451, under the Project Name of "Arizona Cooperative Grid Modernization Project ("ACGM")". The Prime Recipient in the grant is listed as Southwest Transmission Cooperative, Inc. ("SWTC"). Over the past year MEC has been installing SMART meters[5] and substation equipment using funds from the grant. Seventy one percent of the funds have been expended; ninety seven percent have been encumbered. Approximately forty percent of MEC customers presently have SMART meters installed.

MEC has also been pursuing an aggressive program of installing solar photovoltaic ("PV") panels on schools and public buildings in the service area over the past three years as approved in Mohave's Renewable Energy Standard and Tariff ("REST") Plans and using revenue from the required REST Tariff. MEC's renewable energy incentive program for residential and commercial members has experienced a level of incentives available under the REST budget that has been sufficient to meet the level of demand for the incentives. However, MEC recognizes the high number of low income and fixed income members in its service territory and has implemented the PV for Schools program and solar on other public buildings as a way for more members to benefit from the REST surcharge. The philosophy is to help all members as taxpayers by helping to lower the operating costs of government and schools.

These funds have been used to help pay for solar panel installation on City Hall and the Boys and Girls Club in Bullhead City, which provides cost-effective after school programs for working families, as well as local school buildings in Bullhead City, Fort Mohave, Mohave Valley and Topock. MEC anticipates that all schools in both the Bullhead City and Kingman service areas will have solar panels by the end of 2011. In addition, the local community college has installed 34 kW of solar panels, partially funded with the use of REST funds. MEC has

[5] The SMARTmeters installed on the MEC system do not transmit data using radio frequency; they transmit usage via hard-wire.

been instrumental in helping arrange Federal Department of Energy ARRA grants as well as private donations to supplement the REST funds for these installations.

H. Projected System Growth

MEC provided the following projections for system load growth over the next ten year period. The projections were taken from their 2010 Load Forecast Study and are based on assumptions and methodologies that include both historical weather data and projections for the economy over the next few years. The level of projected load growth seems reasonable for the service territory served by Mohave Electric.

Year	Projected System Peak Demand (MW)	Annual Projected Percent Growth
2011	203.9	1.6%
2012	206.8	1.4%
2013	212.9	2.9%
2014	218.6	2.7%
2015	224.4	2.7%
2016	230.4	2.7%
2017	236.5	2.6%
2018	242.9	2.7%
2019	249.4	2.7%
2020	256.0	2.6%

CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding the engineering evaluation of Mohave Electric's electrical system?

A. Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Mohave Electric:
   a. is operating and maintaining its electrical system properly,
   b. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate.
   c. has an acceptable level of system losses, consistent with the industry guidelines, and
   d. has a satisfactory record of service interruptions in the historic period from 2001 thru 2010, reflecting satisfactory quality of service.
2. Staff recommends that:
   a. Mohave Electric should continue with planned system improvements and additions as provided for in the 2008-2011 Construction Work Plan.
   b. Mohave Electric should continue with its plans in utilizing the SMART grid grant and with its REST plan.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF) MOHAVE ELECTRIC COOPERATIVE, INC. FOR) A DETERMINATION OF THE FAIR VALUE OF) ITS PROPERTY FOR RATE MAKING PRUPOSES,) TO FIX A JUST AND REASONABLE RETURN) AND TO APPROVE RATES DESIGNED TO) DEVELOP SUCH A RETURN)	DOCKET NO. E-01750A-11-0136

DIRECT

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

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MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Staff's testimony contains recommendations regarding Mohave Electric Cooperative, Inc.'s proposed modifications regarding its Service Rules and Regulations and Rates and Charges for Other Services.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division ("Staff") of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of various utility applications and review of utility tariff filings. I have been employed by the Arizona Corporation Commission since August 2006.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01750A-11-0136?

A. Yes.

Q. What is the purpose of your testimony in this case?

A. My testimony provides Staff's analysis and recommendations regarding the proposed changes to Mohave Electric Cooperative, Inc.'s ("Mohave") Rates and Charges for Other Services and Service Rules and Regulations.

RATES AND CHARGES FOR OTHER SERVICES

Q. What changes has Mohave proposed to its current standard offer tariff-rates and charges for other services?

A. Mohave is proposing to revise its Regular Hours - Establishment, Re-Establishment, and Reconnection Fees. Currently Mohave charges an Establishment Fee of $25.00, a Reconnection Fee of $25.00, and a Re-Establishment Fee of $50.00. Mohave is proposing to increase the Establishment and Reconnection Fees to $40.00 from the current $25.00 and decrease the Re-Establishment Fee to $40.00 from the current $50.00.

In addition, Mohave is proposing to revise its After Hours - Establishment, Re-Establishment, and Reconnection Fees. For After Hours service, currently Mohave's charges an Establishment Fee of $50.00, a Reconnection Fee of $50.00, and a Re-Establishment Fee of $75.00. Mohave is proposing to increase the Establishment and Reconnection Fees to $60.00 from the current $50.00 and decrease the Re-Establishment Fee to $60.00 from the current $75.00.

Q. Has Mohave made any other revisions to its proposed Standard Offer Tariff-Rates and Charges for Other Services?

A. Yes. As a response to Staff's Data Request, Mohave revised the structure of its Standard Offer Tariff-Rates and Charges for Other Services (see Exhibit CA-5.6(b)). Mohave indicated that it does not distinguish between service establishment, re-establishment, and reconnection fees. Therefore, Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services as revised, eliminates the redundancies in categorizing the fees. Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services as revised only distinguishes between the proposed Regular Hours and After Hours fees for these services.

In addition to the revisions described above, Mohave is proposing to revise the following fees included in its Standard Offer Tariff-Rates and Charges for Other Services:

Service Fee	Current Fee Amount	Proposed Fee Amount
Meter Re-Read*	$5.00	$25.00
Meter Test Shop Test Independent Lab Test**	 $10.00 $25.00	 $40.00 $40.00
Insufficient Funds	$15.00	$25.00
Finance Charge***	15%	1.5%
Late Fee Penalty	0	1.5%
Interest on Customer Deposits****	6%	One Year Treasury Constant Maturities Rate
Service Availability Charge	8%	0
Customer Information Charge	0	$50.00

*No charge for read error
**Lab Costs are in addition to the fee
***Charged to customers on the Deferred Payment Plan
****Established on the first business day of the year, as published by the Federal Reserve

Mohave is also removing the reference to the Pole Attachment Rental fee. This fee is charged for the use of its poles by third parties (i.e. cable companies). It is not for utility services and is not set by the Commission.

Q. Did Mohave provide justification for proposing to revise its Rates and Charges for Other Services?

A. Mohave provided information regarding the costs incurred for each service above, with the exception of the Customer Information Charge. The proposed Customer Information Charge would be charged when Mohave is requested to gather information not readily available from its system. These requests would not include typical billing information requests from customers, but rather consumption data requests from power consultants and organizations that would require Mohave to obtain large volumes of information to satisfy such a request. However, Mohave did not provide a cost-based justification for the proposed Customer Information Charge. In addition, Mohave indicated that such requests for information are historically not a frequent occurrence (see Exhibit CA-5.27).

The cost information Mohave did provide related to the other proposed Rates and Charges for Other Services indicates that Mohave would recover a greater portion of its costs but not all of the costs incurred. Staff believes that the proposed charges are appropriate. Therefore, Staff recommends approval of Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services, as specified in the revision attached as Exhibit CA-5.27, excluding the Customer Information Charge.

Q. Please describe Mohave's proposed changes to its Credit Card Payment Rate Schedule.

A. Further, Mohave has proposed revisions to its current Credit Card Payment Rate Schedule (Exhibit CA-5.21). Mohave is not proposing any changes except to rename the tariff Alternative Payment Rate Schedule, eliminate reference to credit card payments and add reference to alternative payments which would include all payment methods other than cash or check (including cashier's check and certified check), and clarify the reference to the potential bank transaction fee. Should a financial institution not charge a fee to Mohave, the fee would not be charged to Mohave's customers. Staff recommends that Mohave's proposed revisions to its Alternative Payment Rate Schedule be approved.

SERVICE RULES AND REGULATIONS

Q. Has Mohave proposed any modifications to its Service Rules and Regulations?

A. Yes. Mohave has proposed several changes to its Service Rules and Regulations. Many of the proposed changes are substantive, but there are a few proposed changes that are merely clarifications. Staff will only be addressing the substantive revisions proposed by Mohave.

Section 102-Establishing Electric Service

Q. Did Mohave propose prepaid metering in its Service Rules and Regulations?

A. Yes. Mohave has proposed to include prepaid metering as a subsection of Section 102-Establishing Electric Service of its Service Rules and Regulations. In its application, Mohave did not provide any analysis relating to the implementation of prepaid metering. Staff does not believe Mohave's proposal provides adequate information regarding the payment option. Although Mohave did provide responses to Staff's data requests pertaining to its prepaid metering option, Staff believes that approval of prepaid metering would be premature at this time. Staff believes that Mohave should engage in discussions with stakeholders and other interested parties to further evaluate and assess its proposal. In addition, Staff believes that Mohave would benefit from modeling its proposal after the Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC") application for its Experimental Pre-Paid Residential Tariff (Docket E-01575A-11-0439). Staff recommends that Mohave remove SubSection 102-I: Prepaid Metering from its proposed Service Rules and Regulations at this time. If Mohave wishes to pursue a pre-pay option, Staff recommends that Mohave file, in a separate docket, an application for Commission approval of prepaid metering.

Section 106-Line Extensions to Individuals and Section 107-Construction of Line Extensions within Subdivisions

Q. Please explain the changes Mohave is proposing to its current line extension allowance policies.

A. Currently, for individuals not located within a subdivision, Mohave offers 625 feet of free footage allowance to individuals requesting a single-phase line extension and 225 feet of free footage allowance to individuals requesting a three-phase line extension. Mohave is proposing to offer an allowance of $1,750 for single phase line extensions and $2,500 for three phase line extensions.

In addition, for line extensions within a subdivision, Mohave's current free footage allowance is 500 feet for single-phase line extensions and 225 feet for three-phase line extensions. Mohave is proposing to offer an allowance of $800 for single-phase line extensions and $2,500 for three-phase line extensions.

Mohave states that a line extension allowance based on an actual footage does not account for inflation, deflation, and increases in the cost of materials. Further, Mohave states that a line extension allowance based on a dollar amount allows for adjustments during periods of inflation and deflation. The tables below compare Mohave's current and proposed line extension allowance for individuals not within a subdivision and within a subdivision.

Not within a Subdivision

	Current LEP*	Equivalent Dollar Amount-Current	Proposed LEP*	Equivalent Footage Amount-Proposed
Single-Phase	625 feet	$5,913	$1,750	132 feet
Three-Phase	225 feet	$3,195	$2,500	108 feet

***LEP-Line Extension Policy**

Within a Subdivision (Paid by the Developer)

	Current LEP*	Equivalent Dollar Amount-Current	Proposed LEP*	Equivalent Footage Amount-Proposed
Single-Phase	500 feet	$2,390	$800	167 feet
Three-Phase	225 feet	$5,171	$2,500	109 feet

***LEP-Line Extension Policy**

Q. Does Staff agree with Mohave's proposed revisions?

A. Staff does agree that a line extension policy based on a dollar amount would provide greater flexibility during periods of economic fluctuations. In addition, Staff believes that Mohave's proposed line extension allowance would be beneficial for its customers. However, Mohave is proposing to include the cost of a transformer as part of the proposed line extension allowance amount for individuals not within a subdivision. Staff does not believe that individual applicants should pay for the cost of a transformer (See Staff recommendations in the Arizona Public Service Company application for approval of Version 12 of Service Schedule 3 and Agreement, Docket No. E-01345A-11-0207). With Staff's proposal, a single-phase line extension allowance of $1,750 would equate to approximately 185 feet and a three-phase line extension allowance of $2,500 would equate to approximately 176 feet. This is compared to 132 feet and 108 feet respectively under Mohave's proposal. Therefore, Staff recommends that Mohave not include the cost of the transformer for individuals not within a subdivision requesting single-phase or three-phase service. In addition, Staff recommends that Mohave's proposed revisions to single-phase and three-phase line extension allowances within a subdivision be approved.

Staff further recommends that any potential customer who has been given the current line extension free footage allowance estimate or quote by Mohave up to one year prior to an Order in this matter should be given the line extension free footage allowance as specified in Mohave's current Service Rules and Regulations.

Section 111-Termination of Service

Q. Please explain Mohave's proposed changes to SubSection 111-A.

A. Mohave has proposed to modify language in its Service Rules and Regulations that would result in inconsistencies with the Arizona Administrative Code ("A.A.C.") by removing specific guidelines that Arizona Electric Utilities are required to follow.

Mohave has proposed to remove A.A.C. R14-2-211.A.3 from its Service Rules and Regulations. A.A.C. R14-2-211.A.3 specifies that a Utility cannot disconnect service to customers for "[n]onpayment of a bill for another class of service." In addition, Mohave has proposed language in its proposed Service Rules and Regulations that differs from the Commission's Rules regarding termination of residential service A.A.C. R14-2-211.B.3 where the customer has the inability to pay (A.A.C. R14-2-211.A.5.a and A.A.C. R14-2-211.A.5.b.). In addition, Mohave has proposed to remove A.A.C. R14-2-211.A.6.b, which refers to notifying a third party previously designated by the customer of a pending disconnect. Mohave has indicated that it has no objection to including the language in its proposed Service Rules and Regulations. Staff notes that there is a minor reference error on page 46 of Mohave's proposed Service Rules and Regulations (Point 1.f. should reference c. and d. respectively). Staff believes that Mohave's proposals conflict with the Commission's Rules. Therefore, Staff recommends that Mohave be required to file revised Service Rules and Regulations which include the language referenced above.

The following is information that has not been included in Mohave's proposed Service Rules and Regulations:

- A.A.C. R14-2-211.B.3 which refers to maintaining records of terminations of service without notice;
- A.A.C. R14-2-211.C.2 which refers to maintaining records of terminations with notice;
- A.A.C. R14-2-211.D.2.d which refers to the minimum information that must be included in advance written notice of disconnection from Utility;
- A.A.C. R14-2-211.E.4 which refers to a personal visit from a representative from the Utility in order to disconnect service with notice; and
- A.A.C. R14-2-211.E.5 which refers to the Utility's right to remove its property from a customer's premises

Decision No. 57172 dated November 29, 1990, approved Mohave's current Service Rules and Regulations with the exclusion of the above requirements. Staff recommends that the above guidelines should be included in Mohave's proposed Service Rules and Regulations.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A.

1. Staff recommends approval of Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services, as specified in the revision attached as Exhibit CA-5.6(b) of this testimony, except for the proposed Customer Information Charge.

2. Staff recommends approval of Mohave's Alternative Payment Rate Schedule as revised in Exhibit CA-5.21, of this testimony.

3. Staff recommends that Mohave remove's Prepaid Metering not be approved at this time, as discussed in this testimony.

4. If Mohave wishes to pursue a pre-pay option, Staff recommends that Mohave file in a separate docket, an application for Commission approval of prepaid metering, as discussed in this testimony.

5. Staff recommends that Mohave not charge the cost of the transformer to individuals not within a subdivision requesting single phase or three phase service, as discussed in this testimony.

6. Staff recommends that Mohave's proposed revisions to single phase and three phase line extension allowances within a subdivision be approved, as discussed in this testimony.

7. Staff further recommends that any potential customer who has been given the current line extension free footage allowance estimate or quote by Mohave up to one year prior to an Order in this matter should be given the line extension free footage allowance as specified in Mohave current Service Rules and Regulation, as discussed in this testimony.

8. Staff recommends that Mohave be required to file revised Service Rules and Regulations which include the language from the Arizona Administrative Code as discussed in this testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

1999 Arena Drive
Bullhead City, Arizona 86442
Filed By: J. Tyler Carlson
Title: CEO/General Manager

Effective Date: ____________________

STANDARD OFFER TARIFF

RATES AND CHARGES FOR OTHER SERVICES

Rate

OTHER SERVICE CHARGES

Establishment of Service-Regular Hours (Incl. Re-Establishment & Reconnection)		$40.00
~~Establishment of Service~~ After Hours Service		$60.00
~~Re-Establishment of Service-Regular Hours~~		~~$40.00~~
~~Re-Establishment of Service-After Hours~~		~~$60.00~~
~~Reconnection of Service-Regular Hours~~		~~$40.00~~
~~Reconnection of Service-After Hours~~		~~$60.00~~
Meter Re-Read Charge	(No Charge for Read Error)	$25.00
Meter Test Charges:		
	(a) Shop Test	$40.00
	(b) Independent Lab Test	$40.00 Plus Lab Cost
Insufficient Funds Payment		$25.00
Finance Charge-Deferred Payment Plan (Monthly)		1.50%
~~Finance Charge-Delinquent Balances~~Late Fee Penalty (Monthly)		1.50%
Credit Card Service Charge	(Percentage of Total Payment)	~~3.00%~~Applicable Service Charge
Interest Rate on Customer Deposits		~~Annual Three Month Commercial Paper~~ One Year Treasury Constant Maturities Rate Established Annually Each January 1
~~Pole Attachment Rental~~		~~$21.21~~
Service Availability		$0.00
Customer Information Charge		$50.00

ELECTRIC RATES

RATES AND CHARGES FOR OTHER SERVICES

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the service sold hereunder.

Other Charges

Other charges may be applicable subject to approval by the Arizona Corporation Commission.

RESPONSE-CA-5.21

MOHAVE ELECTRIC COOPERATIVE, INC

~~CREDIT CARD~~ALTERNATIVE PAYMENT RATE SCHEDULE

Type of Service

This tariff permits Cooperative Members/Consumers to pay for Mohave Electric Cooperative's sales and services by means other than cash, check drawn on the Consumer's account maintained at a "bank" (as defined by A.R.S. § 47-4105), cashier's check or certified check. Alternative Payment includes, but is not necessarily limited to, credit cards and debit cards.~~of credit card ("Mastercard, "Visa", and "Discover") rather than cash, check or currently accepted method of payment.~~ ~~Offering this optional method of payment responds to changes in the Consumers lifestyle and in acceptable good business practices. Payment by credit card is an alternative and optional method of paying for services and sales provided by the Cooperative.~~

Availability

Alternative Payment ~~by credit card~~ shall be available to all Mohave Electric Cooperative Members/Consumers receiving sales and services provided by Mohave Electric Cooperative. ~~Only "Mastercard", "Visa", or "Discover" credit cards will be accepted.~~

Optional Method of Payment

Alternative Payment ~~by credit card~~ is purely optional for the Consumer. The Cooperative will continue to accept cash, check drawn on the Consumer's account maintained at a "bank" (as defined by A.R.S. § 47-4105), cashier's check or certified check.~~; all other forms of payment normally used by the Cooperative will be maintained.~~

Extra Charge Involved

The use of ~~credit cards for~~ Alternative ~~p~~Payments is administered by a local bank. The bank charges a service charge for each transaction. In order to maintain its financial integrity and to ensure Consumers using ~~this optional payment plan~~ Alternative Payment pay the cost thereof, the Cooperative may pass through the bank's ~~a~~ service charge to the Consumers utilizing the service. The Cooperative may add to all ~~credit card payments~~Alternative Payments the ~~current~~ service ~~fee~~ charge~~which is reflected as a percentage of the total bill paid~~ (hereinafter "bank ~~percentage~~ transaction charge").

Awareness of Transaction Charge

In order to assure that Consumers desiring to use a credit card for payment are aware of the extra charge:

1. All Cooperative publicity dealing with the availability of payment by credit cards will indicate that ~~credit card payments~~Alternative Payments may have the current ~~percentage~~ bank transaction charge added to the payment.
2. Cooperative personnel will be instructed that whenever discussing the availability of the ~~credit card payment~~Alternative Payment option with a Consumer, they will inform the Consumer that ~~a~~the current bank ~~percentage~~ transaction charge may be added to the payment; and
3. The current bank ~~percentage~~ transaction charge (added as a transaction cost) will be reflected in the Consumer's copy of his/her credit card receipt.

Conditional Acceptance of Payment

Payment by credit card shall not be deemed accepted by the Cooperative unless and until accepted and paid by the issuing bank. Any card found to be dishonored shall be immediately deemed rejected by the issuing bank and the Consumer's account status shall be the same as if no payment were tendered.

EXHIBIT 3

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
SEPTEMBER 21, 2011

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

The Following Questions Relate to the Proposed Rates and Charges for Other Services

CA – 5.27 Please specify the costs, if any, associated with the Customer Information Charge that were incurred by Mohave in 2009 and 2010. In addition, please explain why Mohave did not include this charge in Schedule N-3.1 of the application.

Response: **Mohave did not track time or costs associated with customer information requests in 2009 and 2010. The Cooperative estimates that one to two hours were spent on each request, and this could increase due to the legacy system reference.**

Mohave proposes this charge as a new charge. Customer information requests of this type historically have been rare, however requests of this type are increasing, especially for Cooperative's commercial customers.

Prepared by: **A. Lauxman, CFO**
Mohave Electric Cooperative, Incorporated

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF) MOHAVE ELECTRIC COOPERATIVE, INC. FOR) A DETERMINATION OF THE FAIR VALUE OF) ITS PROPERTY FOR RATE MAKING PRUPOSES,) TO FIX A JUST AND REASONABLE RETURN) AND TO APPROVE RATES DESIGNED TO) DEVELOP SUCH A RETURN)	DOCKET NO. E-01750A-11-0136

SURREBUTTAL

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

EXHIBIT
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EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Staff's surrebuttal testimony contains recommendations regarding Mohave Electric Cooperative, Inc.'s ("Mohave") line extension policy and prepaid metering.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division ("Staff") of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of various utility applications and review of utility tariff filings. I have been employed by the Arizona Corporation Commission since August 2006.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. As part of your employment responsibilities, were you assigned to review Mohave Electric Cooperative, Inc.'s ("Mohave") rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimony of Michael Searcy on behalf of Mohave concerning Staff's recommendations regarding Mohave's proposed line extension policy and prepaid metering.

Q. Does Staff agree with Mohave's alternative regarding its proposal to include no more than fifty percent (50%) of the cost of the transformer as part of its line extension allowance amount for individuals not within a subdivision?

A. No. Staff continues to recommend that Mohave not charge for the cost of a transformer as part of its line extension allowance amount for individuals not within a subdivision. Please refer to Staff's direct testimony filed January 12, 2012. In addition, in the on-going

Navopache Electric Cooperative, Inc. rate proceeding. Staff has also recommended that the cost of a transformer not be included as part of the line extension allowance for individual customers. Please refer to the direct testimony of Richard Lloyd filed February 1, 2012, in Docket No. E-01787A-11-0186.

Further, Staff continues to believe that any potential customer who has been given the current line extension free footage allowance estimate or quote by Mohave up to one year prior to an Order in this matter should be given the line extension free footage allowance as specified in Mohave's current Service Rules and Regulations.

Q. **Does Staff agree with Mohave's proposal to include prepaid metering service as part of its Service Rules and Regulations?**

A. Staff continues to believe that Mohave should further investigate and evaluate its proposal for prepaid metering service and file, in a separate docket, an application for Commission approval. However, in the alternative, should the Commission determine that Mohave's proposal is appropriate at this time; Staff recommends that Mohave's prepaid metering option be approved with the following conditions:

- Mohave participate in stakeholder meetings in an effort to improve its prepaid metering service specifically for its income restricted customers;
- Mohave file a request for the appropriate waivers of the Commission's Rules including but not limited to disconnection and metering. However, disconnection waivers should not be waived with respect to extreme weather events (refer to A.A.C. R14-2-201.46) or conditions and customers specified under A.A.C. R14-2-211.A.5 and for those customers under appropriate circumstances but beyond the scope of A.A.C. R14-2-211.A.5;
- Mohave file for Staff review of its proposed Prepaid Metering Agreement, and any promotional/advertising material to be used, prior to implementation;
- Mohave develop for Staff review, prior to implementation, information to be given to potential prepaid metering customers that provides information detailing the classes of customers who qualify for prepaid metering, the customers for

whom prepaid metering is reasonable and appropriate, and the rules and requirements of the prepaid metering option (to be provided prior to signing the proposed Prepaid Metering Agreement). This recommended documentation should be signed and/or initialed and dated as being read and understood by the customer prior to the Prepaid Metering Agreement being signed by the customer.

- Mohave be required to file a prepaid metering tariff that includes the daily rates for the charges specified in the proposed Standard Offer Residential Service Tariff;

- Mohave be required to file, as a compliance item, a revised RES Tariff that includes a section for prepaid metering customers that indicates the daily REST surcharge that would be charged. The method for calculating the daily REST surcharge for prepaid metering customers should be the REST monthly maximum approved by the Commission divided by 30 days; and

- Mohave be required to file, in this docket, an annual report with the following information:

    - The number of prepaid metering customers per month;

    - The number of disconnects per account per month, specifying the number of low-income disconnections;

    - The number of prepaid metering customers that have been disconnected for 24 hours or more (in 24 hour increments) and the number of accounts with repeated disconnections; and

    - A summary of any unforeseen issues that could impact the implementation of or the future progress of the prepaid metering option and recommendations on ways to improve these potential issues.

    - The number of customer complaints specific to prepaid metering

In addition, Staff believes that the following language should be removed from Mohave's proposed Prepaid Metering Agreement:

> Electric service is subject to immediate disconnection any time an account does not have a credit (prepaid) balance, even if the customer has submitted medical documentation that termination would be especially dangerous to a permanent resident of the premises or where life supporting equipment dependent on utility service is in use.

Staff believes that this language is inconsistent with the Commission Rules regarding termination of service. Further, Staff believes that Mohave's proposed Prepaid Metering Agreement specify those customers in which Staff has recommended disconnection waivers not be granted.

Staff notes that Exhibit 2 of Tyler Carlson's rebuttal testimony is unclear and appears to be inconsistent with Mohave's proposed Subsection 102-I.1.e. This section indicates that if a prepaid metering customer fails to make a payment and the account is disconnected, the customer can make a payment, including the applicable Reconnection/Establishment Fee. However, the proposed Prepaid Metering Agreement indicates that only a $20.00 minimum is required. Staff believes that Mohave should clarify the exact charges prepaid metering customers would pay in order to reconnect an account in both its Prepaid Metering Agreement and its Service Rules and Regulations.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. 1. Staff continues to recommend that Mohave not charge the cost of the transformer to individuals not within a subdivision requesting single phase or three phase service, as discussed in Staff's direct testimony.

2. Staff continues to recommend that Mohave file, in a separate docket, an application for Commission approval of prepaid metering, no later than 120 days after a Decision in this matter, as discussed in Staff's direct testimony. However, should the Commission approve Mohave's proposed prepaid metering service, Staff recommends the conditions specified above be included.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	)	DOCKET NO. E-01750A-11-0136

DIRECT

TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

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SCHEDULES

EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Mohave Electric Cooperative, Inc. ("Mohave Electric" or "Cooperative") is a certificated Arizona-based non-profit rural electric distribution cooperative. Mohave Electric provides electric service to approximately 38,577 customers within areas of Mohave, Coconino, and Yavapai counties, Arizona.

Mohave Electric proposed a $2,994,231, or 3.94 percent, revenue increase from $76,068,006 to $79,062,237. The proposed revenue requirement would produce an operating margin[1] before interest on long-term debt of $3,605,952 for a 7.50 percent rate of return on an original cost rate base of $48,083,871 and produce a 1.67 times interest earned ratio ("TIER").

Staff recommends a $2,905,709, or 3.82 percent, revenue increase from $76,068,006 to $78,973,715. This recommended revenue requirement would produce an operating margin[2] before interest on long-term debt of $3,550,132 for a 7.38 percent rate of return on an original cost rate base of $48,083,871 and produces a 1.64 TIER.

STAFF RECOMMENDATIONS

1. Staff recommends a revenue requirement of $78,973,715.

2. Staff further recommends that the Cooperative's request to eliminate the nine million dollar cash or cash equivalent reserve requirement ordered in Decision No. 72216, dated March 9, 2011, be approved.

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[1] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,605,952 amount results in a 7.50 percent rate of return on a $48,083,871 rate base and represents 4.74 percent of the Cooperative's total operating revenue of $76,068,006.
[2] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,550,132 amount results in a 7.38 percent rate of return on a $48,083,871 rate base and represents 4.67 percent of the Cooperative's total operating revenue of $76,068,006.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission in August 1996, I have participated in numerous rate cases and other regulatory proceedings involving electric, gas, water, and wastewater utilities. I have testified on matters involving regulatory accounting and auditing. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") on ratemaking and accounting designed to provide continuing and updated education in these areas.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating revenues and expenses and revenue requirement regarding Mohave Electric Cooperative, Inc.'s ("Mohave Electric" or "Cooperative") application for a permanent rate increase.

Q. Who else is providing Staff testimony and what issues will they address?

A. Staff witness Jerry Mendl is presenting Staff's base cost of power recommendation. Staff witness Candrea Allen is presenting Staff's recommendation concerning the Cooperative's Rules, Regulations and DSM program. Staff witness Bentley Erdwurm is presenting Staff's rate design recommendations. Staff witness Prem Bahl is presenting Staff's cost of service and engineering analysis and recommendations.

BACKGROUND

Q. Please review the background of this application.

A. Mohave Electric is a certificated Arizona-based non-profit rural electric distribution cooperative. Mohave Electric provides electric service to approximately 38,577 customers within areas of Mohave, Coconino, and Yavapai counties, Arizona.

Mohave Electric filed an application for a permanent rate increase on March 30, 2011. On June 27, 2011, Staff filed a letter declaring the application sufficient. Mohave Electric's current rates were authorized in Decision No. 57172, dated November 29, 1990.

Q. What are the primary reasons for the Cooperative's requested permanent rate increase?

A. The Cooperative states that it experienced an adjusted test year operating loss of $965,385. According to the Cooperative, the primary reasons it filed the application are to enable it to meet operating expenses, repay its financing and make improvements to its system in order to maintain adequate and reliable service within its certificated area.

Q. Is Mohave Electric requesting any other approvals?

A. Yes, Mohave Electric is requesting to eliminate the nine million dollar cash or cash equivalent reserve requirement ordered in Decision No. 72216, dated March 9, 2011.

CONSUMER SERVICES

Q. Please provide a brief history of customer complaints received by the Commission regarding Mohave Electric.

A. Staff reviewed the Commission's records for the period of January 1, 2008 through November 8, 2011, and found 64 complaints. All complaints have been resolved and closed. There were eight opinions opposing the rate increase.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Cooperative's filing.

A. The Cooperative proposes total annual revenue of $79,062,237 as shown on Schedule CSB-1. This proposed revenue provides a $2,994,231, or 3.94 percent, revenue increase over adjusted Test Year revenues of $76,068,006. Operating revenue of $79,062,237 would produce an operating margin[3] before interest on long-term debt of $3,605,952 for a 7.50 percent rate of return on an original cost rate base ("OCRB") of $48,083,871 and produces a 1.67 Times Interest Earned Ratio ("TIER").

[3] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,605,952 amount results in a 7.50 percent rate of return on a $48,083,871 rate base and represents 4.74 percent of the Cooperative's total operating revenue of $76,068,006.

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual revenue of $78,973,715 as shown on Schedule CSB-1. This recommended revenue provides a $2,905,709 or 3.82 percent revenue increase over adjusted test year revenues of $76,068,006. Operating revenue of $78,973,715 produces an operating margin[4] before interest on long-term debt of $3,550,132 for a 7.38 percent rate of return on an OCRB of $48,083,871 and produces a 1.64 TIER.

Q. What test year did Mohave Electric utilize in this filing?

A. Mohave Electric's rate filing is based on the twelve months ended December 31, 2009, ("test year"). This test year was approximately 15 months old at the time the Cooperative filed its rate application on March 30, 2011. Subsequently, the Cooperative agreed to provide 2010 data. Since the 2010 data reflected the most recent historical 12-month period, consistent with Commission Rules, and provided Staff with more recent information to perform its analysis, Staff updated the 2009 test year to 2010.

Q. Please summarize the rate base and operating margin recommendations and adjustments addressed in your testimony for Mohave Electric.

A. Staff made no adjustments to rate base. Staff's operating margin adjustments are as follows:

Operating Margin Adjustments

<u>Base Cost of Power Revenue, Purchased Power Cost Adjustor ("PPCA") Revenue and Purchased Power Expense</u> – This adjustment increases revenues as a result of matching the Base Cost of Power Revenue to the Cooperative-proposed purchased power expense,

[4] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,550,132 amount results in a 7.38 percent rate of return on a $48,083,871 rate base and represents 4.67 percent of the Cooperative's total operating revenue of $76,068,006.

eliminates the PPCA revenues from operating revenues, and removes ineligible power costs from the Cooperative-proposed purchased power expense.

<u>Administrative and General Revenue and Expense</u> – This adjustment reclassifies certain costs removed from the base cost of power revenue and purchased power expense and reclassifies them to margin revenue and administrative and general expense.

RATE BASE

Fair Value Rate Base

Q. Did the Cooperative prepare a schedule showing the elements of Reconstruction Cost New Rate Base?

A. No, the Cooperative did not. The Cooperative's filing treats the OCRB the same as the fair value rate base.

Rate Base Summary

Q. Please summarize Staff's adjustments to Mohave Electric's rate base shown on Schedule CSB-2.

A. Staff made no adjustments to Mohave Electric's proposed rate base. Staff recommends a rate base of $48,083,871 which is the same as the Cooperative's proposed rate base.

Operating Margin

Operating Margin Summary

Q. What are the results of Staff's analysis of test year revenues, expenses and operating margin?

A. As shown on Schedules CSB-3 and CSB-4, Staff's analysis resulted in test year revenues of $76,068,006, expenses of $75,423,583 and operating margin before interest expense of $644,423.

Operating Margin Adjustment No. 1 – Base Cost of Power Revenue, Purchased Power Cost Adjustor ("PPCA") Revenue, and Purchased Power Expense

Adjustment to Base Cost of Power Revenue and PPCA Revenue

Q. Explain the purpose of the break-out of the total revenue from sales of electricity into components as shown on Schedules CSB-4 and CSB-5.

A. The purpose is to show the portion of base rates revenue that is generated to recover the purchased power cost separately from the portion of base rates revenue that is generated to recover the remaining cost of service components.

Q. What amount is Mohave Electric proposing for Base Cost of PPCA revenue, and third party sales revenue?

A. The Cooperative has proposed base cost of power revenue of approximately $43,074,463[5], PPCA revenue of $15,505,234, and third party sales revenue of $3,222,980 for a total of $61,802,677.

---

[5] $43,074,242 base cost of power revenue +221 rounding/reconciling amount = $43,074,463.

Q. For ratemaking purposes, is it appropriate to include monies from the Cooperative's PPCA in operating revenues?

A. No, it is not appropriate. The PPCA revenues are set using a mechanism that is different from that used to set base rates. Further, the PPCA can change outside of a rate case based on over or under collections in the Cooperative's fuel bank.

Q. Does Mohave Electric's base cost of power revenue match its purchased power expense?

A. No. The Cooperative's filing reflects a $43,074,463 test year base cost of power revenue and a $61,802,677 test year purchased power expense.

Q. What is the cause of the mismatch?

A. The Cooperative did not make a pro forma adjustment to its base cost of power revenue to reflect that, on a going forward basis, a larger amount of its proposed purchase power expense will be recovered through the base cost of power rate.

Q. Should Mohave Electric's test year total power revenue equal purchased power expense?

A. Yes. The Cooperative has a purchased power adjustor mechanism that facilitates full recovery of all purchased power costs. The adjustor mechanism ensures that the Cooperative neither over nor under recover purchased power cost. This means that changes in the cost of purchased power do not affect income. The difference between the amount collected from customers and the amount paid to power suppliers for purchased power in any year due to timing differences is reflected on the balance sheet as an asset or liability, not on the income statement.

Failure to recognize equal amounts for the revenue and expense associated with purchased power when an adjustor mechanism is in effect is inconsistent with the United States Department of Agriculture Rural Utility Service Uniform System of Accounts. This mismatch results in a misstatement of income. Therefore, any pro forma adjustment to purchased power expense must be offset by an equal adjustment to total power revenue.

Q. Did Staff make any other adjustments to the base cost of power revenue?

A. Yes. Staff reduced base cost of power revenue by $594,737 in order to match the $594,737 decrease in purchased power expense recommended by Staff witness, Jerry Mendl. Staff's adjustment is shown on Schedule CSB-5, line 8.

Q. Please summarize the Cooperative's total Power Revenue components and Staff's adjustments to Base Cost of Power Revenue?

A. The Cooperative has proposed base cost of power revenue of approximately $43,074,463[6], PPCA revenue of $15,505,234, and third party sales revenue of $3,222,980, for a total of $61,802,677 for Power Revenue.

Staff removed $15,505,234 in PPCA revenues ($61,802,677 - $15,505,234 = $46,297,443) because the PPCA rate is set using a different mechanism and can be changed outside of a rate case; therefore, its inclusion in test year revenue is inappropriate for ratemaking purposes. Staff then increased the base cost of power by $15,505,234 ($46,297,443 + $15,505,234 = $61,802,677) to match the Cooperative-proposed purchased power expense of $61,802,677. Next, Staff decreased the base cost of power revenue by $594,737 to match Staff's proposed purchased power expense of $61,207,940 ($61,802,677 - $594,737 = $61,207,940) as shown on Schedule CSB-5.

[6] $43,074,242 base cost of power revenue +221 rounding/reconciling amount = $43,074,463.

Q. What is Staff's recommendation for total power revenue?

A. Staff is recommending $61,207,940 as shown on Schedule CSB-5.

Adjustment to Purchased Power Expense

Q. What purchased power amount did the Cooperative propose?

A. The Cooperative proposed $61,802,677 for purchased power expense.

Q. Did Staff make any adjustment to purchased power expense?

A. Yes, Staff removed $594,737 in costs that were not purchased power costs as discussed in greater detail by Staff witness, Jerry Mendl. Staff reclassified $562,035 in costs related to labor and consulting. Staff disallowed $32,038 related to lobbying and $664 in unsupported costs for a total of $32,702 as shown on Schedules CSB-4 and CSB-6.

Q. What are the direct revenue and expense effects of Staff's recommendation for a lower purchase power expense than the Cooperative?

A. There is no change to income because purchase power expense and base cost of power revenue both decrease by the same amount.

Q. Does Staff's recommendation for a lower purchased power expense affect the amount of power cost the Cooperative will recover?

A. No. A change in the purchased power expense only affects the amount of power cost recovered through base rates. The Cooperative has an adjustor mechanism that provides for matching recovery with actual purchased power costs.

Q. What is Staff's recommendation for purchased power expense?

A. Staff recommends purchased power expense of $61,207,940.

Operating Margin Adjustment No. 2 – Administrative and General Revenue and Expense

Q. What adjustment did Staff make to administrative and general revenue and expense?

A. Staff reclassified expenses of $562,035[7] that were removed from the base cost of power revenue and purchased power expense. Staff added the amount to both administrative and general revenues and expense as shown on Schedules CSB-3 and CSB-6.

Q. What is Staff's recommendation?

A. Staff recommends increasing margin revenue by $594,737 and administrative and general expense by $562,035 as shown on Schedules CSB-4 and CSB-6.

REVENUE REQUIREMENT

Debt Service Coverage

Q. What are the primary factors considered in determining the Cooperative's revenue requirement?

A. Staff's revenue requirement is primarily driven by the revenues needed to pay the principal and interest on long-term debt, and to meet the minimum debt service coverage ("DSC") ratio required by the National Rural Utilities Cooperative Finance Corporation ("RUS"/"CFC"). Additionally, Staff's revenue requirement provides sufficient cash flow to pay operating expenses and to build equity.

Q. What was the amount of the Cooperative's outstanding long-term debt at the end of the test year, and what was the test year interest expense incurred?

A. At the end of the test year, the Cooperative had $37,450,215 in long-term debt, and it incurred $2,161,308 in interest expense.

[7] Staff removed $594,737 from purchased power expense but reclassified only $562,035.

Q. Would you please briefly define the debt service coverage ratio ("DSC") and the TIER?

A. DSC measures an entity's ability to generate cash flow to pay its debt service obligations (interest and principal) from operating activities. It is calculated by dividing (1) earnings before interest, taxes, and depreciation expense by (2) the principal and interest payments. When the DSC is greater than 1.0, operating cash flow is sufficient to cover debt obligations.

TIER measures the number of times operating income will cover interest on long-term debt. It is calculated by dividing (1) operating margin after interest on long-term debt plus interest on long-term debt by (2) interest on long-term debt. When the TIER is greater than 1.0, operating income is sufficient to cover interest expense.

Q. What are Mohave Electric's DSC and TIER requirements?

A. For the loan agreements Mohave Electric has with the RUS/CFC, the DSC and TIER ratio requirements are 1.25 and 1.5, respectively.

Q. Did Staff calculate the DSC differently than the Cooperative?

A. Yes.

Q. How does Mohave Electric calculate DSC?

A. Mohave Electric uses the DSC calculation prescribed by the RUS/CFC. The RUS/CFC includes revenues derived from activities that are not a part of the Cooperative's core electric retail sales business (i.e. non-operating margin interest revenue and cash capital credit revenue). The RUS/CFC calculation is as follows:

For any calendar year add (1) Operating Margins, (2) Non-Operating Margins-Interest, (3) Interest Expense on long-term debt, (4) Depreciation and Amortization Expense, and (5) cash received from capital credits. Divide the sum so obtained by the sum of all payments of Principal and Interest on long-term debt.

Q. How does Staff's DSC calculation differ from the Cooperative's?

A. Staff's calculation is similar but excludes non-operating revenue from interest and capital credits.

Q. Why does Staff exclude non-operating revenue in its DSC calculation?

A. Non-operating revenue tends to be inconsistent from year to year. Staff's calculation measures the Cooperative's ability to make principal and interest payments based solely on the Cooperative's core operating results. Since operating results are generally more consistent than non-operating results, Staff's calculation provides a more reliable indication of ability to service debt.

Q. What revenue is Staff recommending to satisfy Mohave Electric's DSC and TIER requirements?

A. Staff recommends revenue of $78,973,715 to provide a 1.53 DSC and a 1.64 TIER. Staff's proposed revenue would generate enough cash flow to service the Cooperative's debt and comply with CFC debt coverage requirements, allow for reasonable contingencies, and build equity.

Q. What is Staff's recommended increase over the Staff adjusted test year revenue?

A. Staff's recommended revenue of $78,973,715 is a $2,905,709 (or a 3.82 percent) increase over the Staff adjusted test year revenue of $76,068,006.

Q. Is 3.82 percent representative of the increase to customer bills on average with Staff's recommended revenue requirement?

A. Customer bills are comprised of margin costs and the cost of purchased power. The margin cost portion of customer bills would increase on average by 3.82 percent. The cost of power portion of customer bills reflects, on average, the Cooperative's actual cost of purchased power. The cost of purchased power fluctuates and might result in a different increase or decrease in customers' bills.

Revenues from New Service Charge

Q. What amount of increase did the Cooperative propose for Other Revenues?

A. The Cooperative proposed $256,648 as shown on the Cooperative's Supplemental Schedule A-1.0.

Q. Did the Cooperative propose a new service charge?

A. Yes. The Cooperative proposed a new deferred payment plan service charge of 1.5 percent.

Q. What amount of additional revenue would the implementation of the new service charge generate?

A. Mohave Electric estimates that the new service charge would generate approximately $55,820.

Q. Was the additional revenue reflected in the Mohave Electric's proposed revenue requirement?

A. No, it was not.

Q. Did Staff reflect the additional revenue in Staff's recommended revenue requirement?

A. Yes. The additional revenue is reflected in the Other Revenues account.

REQUEST TO ELIMINATE RESERVE REQUIREMENT

Q. What does the Cooperative request to eliminate?

A. Mohave Electric requests to eliminate the nine million dollar cash or cash equivalent reserve requirement ordered in Decision No. 72216, dated March 9, 2011.

Q. Why was the nine million dollar cash or cash equivalent reserve requirement originally recommended?

A. Decision No. 72216 approved Mohave Electric's request for a $28 million loan. Staff's financial analysis determined that both of the Cooperative's TIER and DSC ratios were less than one. A DSC less than one means that debt service obligations cannot be met by cash generated from operations and that another source of funds is needed to avoid default. Consequently, the nine million dollar cash or cash equivalent reserve requirement was recommended.

Q. Will Staff's recommended revenue requirement provide TIER and DSC ratios greater than one?

A. Yes. Therefore, the nine million dollar cash or cash equivalent reserve requirement is no longer needed.

Q. What is Staff's recommendation concerning the reserve requirement?

A. Staff recommends that the Cooperative's request to eliminate its $9 million reserve requirement be approved.

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

Mohave Electric Cooperative, Inc. Schedule CSB-1
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST	
1	Adjusted Operating Margin (Loss) Before Interest on L.T.-Debt	$	611,721	$	644,423
2	Depreciation and Amortization	$	2,239,666	$	2,239,666
3	Income Tax Expense		-		-
4	Long-term Interest Expense	$	2,161,308	$	2,161,308
5a	Principal Repayment	$	1,624,749	$	1,624,749
5b	Interest Income	$	410,049	$	410,049
5c	Cash Capital Credits	$	34,479	$	34,479
6a	**Recommended Increase in Operating Revenue**	$	2,994,231	**$**	**2,905,709**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**		N/A		**3.82%**
6c	Percent Increase (Line 6a / $76,068,006) - Per Cooperative		3.94%		N/A
7	Adjusted Test Year Operating Revenue	$	76,068,006	$	76,068,006
8	**Recommended Annual Operating Revenue**	$	79,062,237	**$**	**78,973,715**
9a	**Recommended Operating Margin Before Interest on L.T.-Debt**	$	3,605,952	**$**	**3,550,132**
9b	Recommended Operating Margin After Interest on L.T.-Debt	$	1,285,224	$	1,229,404
10a	**Recommended Operating TIER Before Intr on LT Debt(L4+L9a)/L4**		1.67		**1.64**
10b	Operating TIER After Interest on LT Debt(L4+L9b)/L4		1.59		1.57
11a	**Recommended DSC (L2+L3+L9a)/(L4+L5) - Per Staff**		N/A		**1.53**
11b	Recommended DSC - Per Cooperative		1.62		N/A
12	**Adjusted Rate Base**	$	48,083,871	**$**	**48,083,871**
13	Rate of Return (L9a / L12)		7.50%		7.38%

References:
Column [A]: Company *Schedules* A-1, C-1, C-3
Column [B]: Staff Schedule CSB-4, Testimony

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COOPERATIVE TEST YEAR UPDATED TO 2010	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 88,890,934	$ -	$ 88,890,934
2	Less: Acc Depreciation & Amortization	(35,708,314)	-	(35,708,314)
3	Net Plant in Service	$ 53,182,620	$ -	$ 53,182,620
	LESS:			
4	Consumer Deposits	$ (2,494,774)	$ -	$ (2,494,774)
5	Consumer Construction Advances	$ (4,596,854)	$ -	$ (4,596,854)
6	Consumer Energy Prepayments	$ (1,322,966)	$ -	$ (1,322,966)
7	Total	(8,414,594)	-	(8,414,594)
	ADD:			
8	Cash Working Capital	$ -	$ -	$ -
9	Materials and Supplies	$ 2,087,854	$ -	$ 2,087,854
10	Prepayments	$ 1,227,991	$ -	$ 1,227,991
11	Total	$ 3,315,845	$ -	$ 3,315,845
12	**Total Rate Base**	$ 48,083,871	$ -	$ 48,083,871

References:
Column [A], Cooperative Schedule B-1
Column [B]:
Column [C]: Column [A] + Column [B]

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Schedule CSB-3

OPERATING MARGIN - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] COOPERATIVE TEST YEAR UPDATED TO 2010	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF RECOMMENDED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:					
1	Margin Revenue (Excludes BCOP Rev & PPCA Rev)	$ 13,658,430	$ 594,737	$ 14,253,167	$ 2,593,241	$ 16,846,408
2						
3	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 14,910,497	$ 57,984,739	$ -	$ 57,984,739
4	Purchased Power Cost Adjustor ("PPCA") Revenue	15,505,234	(15,505,234)	-	-	-
5	Rounding/Reconciling Amount	221	-	221	-	221
6	Subtotal	$ 58,579,697	$ (594,737)	$ 57,984,960	$ -	$ 57,984,960
7	Off System Sales (Third Party Sales)	3,222,980	-	3,222,980	-	3,222,980
8	Subtotal	$ 61,802,677	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
9						
10	Other Revenues	$ 606,899	$ -	$ 606,899	$ 312,468	$ 919,367
13	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**	**$ 0**	**$ 76,068,006**	**$ 2,905,709**	**$ 78,973,715**
14						
15	EXPENSES:					
16	Purchased Power	$ 61,802,677	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
17	Sub Transmission O&M	169,400	-	169,400	-	169,400
18	Distribution - Operations	2,773,698	-	2,773,698	-	2,773,698
19	Distribution - Maintenance	1,194,657	-	1,194,657	-	1,194,657
20	Consumer Accounting	2,227,246	-	2,227,246	-	2,227,246
21	Customer Service	196,226	-	196,226	-	196,226
22	Sales	96,252	-	96,252	-	96,252
23	Administrative and General	4,756,463	562,035	5,318,498	-	5,318,498
24	Depreciation and Amortization	2,239,666	-	2,239,666	-	2,239,666
25	Taxes	-	-	-	-	-
26	Total Operating Expenses	$ 75,456,285	$ (32,702)	$ 75,423,583	$ -	$ 75,423,583
27						
28	Operating Margin Before Interest on L.T.- Debt	$ 611,721	$ 32,702	$ 644,423	$ 2,905,709	$ 3,550,132
29						
30	INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS					
31	Interest on Long-term Debt	$ 2,161,308	$ -	$ 2,161,308	$ -	$ 2,161,308
32	Interest - Other	$ 142,396	$ -	$ 142,396	$ -	$ 142,396
33	Other Dedcutions	$ 17,024	$ -	$ 17,024	$ -	$ 17,024
34	Total Interest & Other Deductions	$ 2,320,728	$ -	$ 2,320,728	$ -	$ 2,320,728
35						
36	MARGINS (LOSS) AFTER INTEREST EXPENSE	$ (1,709,007)	$ 32,702	$ (1,676,305)	$ 2,905,709	$ 1,229,404
37						
38	NON-OPERATING MARGINS					
39	Interest Income	$ 410,049	$ -	$ 410,049	$ -	$ 410,049
	Gain(Loss) Equity Investments	$ 110,369	$ -	$ 110,369	$ -	$ 110,369
40	Other Margins	$ (32,307)	$ -	$ (32,307)	$ -	$ (32,307)
41	G&T Capital Credits	$ 3,509,969	$ -	$ 3,509,969	$ -	$ 3,509,969
42	Other Capital Credits	$ 107,687	$ -	$ 107,687	$ -	$ 107,687
43	Total Non-Operating Margins	$ 4,105,767	$ -	$ 4,105,767	$ -	$ 4,105,767
44						
45	EXTRAORDINARY ITEMS	$ -	$ -	$ -	$ -	$ -
46						
47	NET MARGINS (LOSS)	$ 2,396,760	$ 32,702	$ 2,429,462	$ 2,905,709	$ 5,335,171
48						
49						
50	References:					
51	Column (A): Cooperative Schedule A					
52	Column (B): Schedule CSB-4					
53	Column (C): Column (A) + Column (B)					
54	Column (D): Schedule CSB-1; Testimony					
55	Column (E): Column (C) + Column (D)					

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Schedule CSB-4

SUMMARY OF OPERATING MARGIN ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] PER COOPERATIVE	[B] ADJ #1 Power Revenue, PPCA Revenue, & Purchased Pwr Exp Ref: Sch CSB-5	[C] ADJ #2 Administrative & General Rev & Exp Ref: Sch CSB-6	[D] STAFF ADJUSTED
	REVENUES:				
1	Margin Revenue (Excludes BCOP Rev & PPCA Rev)	$ 13,658,430	$ -	$ 594,737	$ 14,253,167
2					
3	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 14,910,497	$ -	$ 57,984,739
4	Purchased Power Cost Adjustor ("PPCA") Revenue	15,505,234	(15,505,234)	-	-
5	Rounding/Reconciling Amount	221	-	-	221
6	Subtotal	$ 58,579,697	$ (594,737)	$ -	$ 57,984,960
7	Off System Sales (Third Party Sales)	3,222,980	-	-	3,222,980
8	Subtotal	$ 61,802,677	$ (594,737)	$ -	$ 61,207,940
9					
10	Other Revenues	$ 606,899	$ -	$ -	$ 606,899
11					
12	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**	**$ (594,737)**	**$ 594,737**	**$ 76,068,006**
13					
14	***OPERATING EXPENSES:***				
15	Purchased Power	$ 61,802,677	$ (594,737)	$ -	$ 61,207,940
16	SubTransmission Operation and Maintenance	169,400	-	-	169,400
17	Distribution - Operations	2,773,698	-		2,773,698
18	Distribution - Maintenance	1,194,657	-	-	1,194,657
19	Consumer Accounting	2,227,246	-	-	2,227,246
20	Customer Service	196,226	-	-	196,226
21	Sales	96,252	-	-	96,252
22	Administrative and General	4,756,463	-	562,035	5,318,498
23	Depreciation and Amortization	2,239,666	-	-	2,239,666
24	Taxes	-	-	-	-
25	**Total Operating Expenses**	$ 75,456,285	$ (594,737)	$ 562,035	$ 75,423,583
26					
27	**Operating Margin Before Interest on L.T.- Debt**	**$ 611,721**	**$ -**	**$ 32,702**	**$ 644,423**
28					
29	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***				
30	Interest on Long-term Debt	$ 2,161,308	$ -	$ -	$ 2,161,308
31	Interest - Other	142,396	-	-	142,396
32	Other Dedcutions	17,024	-	-	17,024
33	**Total Interest & Other Deductions**	$ 2,320,728	$ -	$ -	$ 2,320,728
34					
35	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	**$ (1,709,007)**	**$ -**	**$ 32,702**	**$ (1,676,305)**
36					
37	***NON-OPERATING MARGINS***				
38	Interest Income	$ 410,049	$ -	$ -	$ 410,049
	Gain(Loss) Equity Investments	110,369	-	-	110,369
39	Other Margins	(32,307)			(32,307)
40	G&T Capital Credits	3,509,969			3,509,969
41	Other Capital Credits	107,687	-	-	107,687
42	**Total Non-Operating Margins**	$ 4,105,767	$ -	$ -	$ 4,105,767
43					
44	***EXTRAORDINARY ITEMS***	$ -	-	-	$ -
45					
46	***NET MARGINS (LOSS)***	$ 2,396,760	$ -	$ 32,702	$ 2,429,462

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 *(Updated to 2010)*

Schedule CSB-5

**OPERATING MARGIN ADJUSTMENT NO. 1 - POWER REVENUE,
PURCHASED POWER COST ADJUSTOR REVENUE, & PURCHASED POWER EXPENSE**

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	
1	*Revenue*				
2	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 0	$ 43,074,242	From Line 39
3	Purchased Power Cost Adjustor ("PPCA") Rev	15,505,234	(15,505,234)	-	From Coop Suppl Sch A-1
4	Rounding/Reconciling Amount	221	-	221	
5	**Subtotal BCOP Revenue & PPCA Revenue**	**$ 58,579,697**	**$ (15,505,234)**	**$ 43,074,463**	
6					
7	Staff Recommended Increase To BCOP Rev	-	15,505,234	15,505,234	
8	Staff Recommended Decrease To BCOP Rev	-	(594,737)	(594,737)	From Line 25
9	**Subtotal Revenue**	**$ -**	**$ 14,910,497**	**$ 14,910,497**	
10					
11	Off System Sales (Third Party Sales)	3,222,980	-	3,222,980	From Coop Suppl Sch A-5
12	**Total Revenue**	**$ 61,802,677**	**$ (594,737)**	**$ 61,207,940**	
13					
14	***Expenses***				
15	Purchased Power	$ 61,802,677	$ -	$ 61,802,677	
16					
17	To Remove In House Labor & Benefits	$ -	(120,042)	(120,042)	From JEM-6, P.2
18	To Remove Legal Services	$ -	(335,233)	(335,233)	From JEM-6, P.2
19	To Remove Lobbying Costs	$ -	(32,038)	(32,038)	From JEM-6, P.2
20	To Remove Costs to Prepare Fuel Bank Reports	$ -	(23,015)	(23,015)	From JEM-6, P.2
21	To Remove Consulting Costs	$ -	(83,745)	(83,745)	From JEM-6, P.2
22	To Remove Unsupported Costs	$ -	(664)	(664)	From JEM-6, P.2
23	Subtotal Expenses	-	(594,737)	(594,737)	
24					
25	**Total Expenses**	**$ 61,802,677**	**$ (594,737)**	**$ 61,207,940**	
26					
27	**Operating Margin (Line 18 - Line 30)**	**$ (0)**	**$ 0**	**$ -**	
28					
29		kWh's Subject		kWh's Subject	
30		to PPA in TY	Adjustment	to PPA in TY	
31	Residential Sales	364,970,959	-	364,970,959	
32	Irrigation Sales	4,302,352	-	4,302,352	
33	Small Commercial	113,810,903	-	113,810,903	
34	Large Commercial	171,559,418	-	171,559,418	
35	Lighting	0	-	0	
36	AES Sales	0	-	0	
37	Test Year Sales (In kWhs) subject to PPA	654,643,632	-	654,643,632	
38	Multiplied by: Base Cost of Power per kWh	0.065798000	-	0.065798000	
39	Total Base Cost of Power	$ 43,074,242	$ -	$ 43,074,242	

References:

Column A: Cooperative Supplemental Schedule A-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01750A-11-0136

SURREBUTTAL

TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

EXHIBIT
S-5

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Staff's surrebuttal testimony recommends total annual revenues of $79,129,535 resulting in a $3,605,952 operating margin before interest on long-term debt or 7.50 percent rate of return on a $48,083,871 rate base. Staff's surrebuttal testimony responds to Mohave's rebuttal testimony on the following issues:

Operating Income:

a. Other Revenue
b. Rate Case Expense

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Crystal S. Brown who filed direct testimony in this case?

A. Yes.

PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. The purpose of my surrebuttal testimony in this proceeding is to respond, on behalf of Staff, to the rebuttal testimony of Mr. Michael W. Searcy who represents Mohave Electric Cooperative, Inc. ("Mohave" or "Cooperative").

Q. What issues will you address?

A. I will address the Other Revenue and Rate Case Expense issues that are discussed in the rebuttal testimony of Mohave's witness Mr. Michael W. Searcy. Staff witness, Mr. Jerry Mendl, will address the purchased power issue.

Q. What is Staff's recommended revenue?

A. Staff recommends total annual revenues of $79,129,535 resulting in a $3,605,952 operating margin before interest on long-term debt or 7.50 percent rate of return on a $48,083,871 rate base.

OPERATING MARGIN

Operating Margin – Other Revenue

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning Other Revenue?

A. Yes.

Q. Does Staff agree with the Cooperative?

A. Yes. In Staff's direct testimony, Staff increased Other Revenues by $55,820. The Cooperative has clarified, in its rebuttal testimony, that the $55,820 for revenues it anticipates receiving from a new deferred payment plan late fee was included in the Cooperative's direct testimony.

Q. Did the Cooperative make any other changes to its Other Revenue?

A. Yes. The Cooperative is increasing Other Revenues in its direct testimony by $3,735 to reflect service charge corrections.

Q. In recognition of the clarification and new information provided by the Cooperative in its rebuttal testimony, is Staff making any changes to its recommendation?

A. Yes. Staff's surrebuttal recommendation increases Other Revenues by $260,383, from $606,899 in its direct testimony to $919,367 in its surrebuttal as shown in surrebuttal Schedule CSB-3. Staff is removing its adjustment to reduce Other Revenues by $55,820 based on the clarification provided by the Cooperative and is reflecting $3,735 in additional revenue as calculated by the Cooperative in its rebuttal testimony.

Q. Is Staff's recommended $867,282 in Other Revenue the same amount as that proposed by the Cooperative in its rebuttal testimony?

A. Yes.

Q. How does Staff's recommended Other Revenue compare to the recommended Other Revenue in Staff's direct testimony?

A. Staff's recommended Other Revenues has decreased by $52,085, from $919,367 in its direct testimony to $867,282 in its surrebuttal testimony.

Operating Margin – Rate Case Expense

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning Rate Case Expense?

A. Yes.

Q. Does Staff agree with the Cooperative?

A. Yes. The Cooperative incurred costs to prepare and file a rate application using a 2009 test year. Additional costs were incurred to comply with Staff's request for a filing using 2010 data. Further, the Company has incurred costs due to Staff's prudence review of its purchased power costs. Moreover, the Cooperative's proposed four-year normalization period is appropriate because Staff is recommending that Mohave be ordered to file a new rate case no later than April 16, 2016. Therefore, Staff has included $100,000 in operating expenses to reflect $400,000 in rate case expense normalized using four years.

Q. What is Staff's surrebuttal recommendation?

A. Staff's surrebuttal recommendation increases revenues by $100,000 as shown in surrebuttal Schedule CSB-4.

Q. How does Staff's recommended Rate Case Expense compare to the recommended Rate Case Expense in Staff's direct testimony?

A. Staff's recommended Rate Case Expense has increased by $100,000, from $0 in its direct testimony to $100,000 in its surrebuttal testimony.

Q. Does this conclude Staff's surrebuttal testimony?

A. Yes, it does.

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL COST	[B] STAFF ORIGINAL COST
1	Adjusted Operating Margin (Loss) Before Interest on L.T.-Debt	$ 611,721	$ 544,423
2	Depreciation and Amortization	$ 2,239,666	$ 2,239,666
3	Income Tax Expense	-	-
4	Long-term Interest Expense	$ 2,161,308	$ 2,161,308
5a	Principal Repayment	$ 1,624,749	$ 1,624,749
5b	Interest Income	$ 410,049	$ 410,049
5c	Cash Capital Credits	$ 34,479	$ 34,479
6a	**Recommended Increase in Operating Revenue**	$ 2,994,231	**$ 3,061,529**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**	N/A	**4.02%**
6c	Percent Increase (Line 6a / $76,068,006) - Per Cooperative	3.94%	N/A
7	Adjusted Test Year Operating Revenue	$ 76,068,006	$ 76,068,006
8	**Recommended Annual Operating Revenue**	$ 79,062,237	**$ 79,129,535**
9a	**Recommended Operating Margin Before Interest on L.T.-Debt**	$ 3,605,952	**$ 3,605,952**
9b	Recommended Operating Margin After Interest on L.T.-Debt	$ 1,285,224	$ 1,285,224
10a	**Recommended Operating TIER Before Intr on LT Debt(L4+L9a)/L4**	1.67	**1.67**
10b	Operating TIER After Interest on LT Debt(L4+L9b)/L4	1.59	1.59
11a	**Recommended DSC (L2+L3+L9a)/(L4+L5) - Per Staff**	N/A	**1.54**
11b	Recommended DSC - Per Cooperative	1.62	N/A
12	**Adjusted Rate Base**	$ 48,083,871	**$ 48,083,871**
13	Rate of Return (L9a / L12)	7.50%	7.50%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedule CSB-4, Testimony

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COOPERATIVE TEST YEAR UPDATED TO 2010	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 88,890,934	$ -	$ 88,890,934
2	Less: Acc Depreciation & Amortization	(35,708,314)	-	(35,708,314)
3	Net Plant in Service	$ 53,182,620	$ -	$ 53,182,620
	LESS:			
4	Consumer Deposits	$ (2,494,774)	$ -	$ (2,494,774)
5	Consumer Construction Advances	$ (4,596,854)	$ -	$ (4,596,854)
6	Consumer Energy Prepayments	$ (1,322,966)	$ -	$ (1,322,966)
7	Total	(8,414,594)	-	(8,414,594)
	ADD:			
8	Cash Working Capital	$ -	$ -	$ -
9	Materials and Supplies	$ 2,087,854	$ -	$ 2,087,854
10	Prepayments	$ 1,227,991	$ -	$ 1,227,991
11	Total	$ 3,315,845	$ -	$ 3,315,845
12	**Total Rate Base**	$ 48,083,871	$ -	$ 48,083,871

References:
Column [A], Cooperative Schedule B-1
Column [B]:
Column [C]: Column [A] + Column [B]

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-3

OPERATING MARGIN - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] COOPERATIVE TEST YEAR UPDATED TO 2010	ADJ NO.	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF RECOMMENDED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:						
1	Margin Revenue (Excludes BCOP Rev & PPCA Rev)	$ 13,658,430		$ 594,737	$ 14,253,167	$ 2,801,146	$ 17,054,313
2							
3	Base Cost of Power ("BCOP") Revenue	$ 43,074,242		$ 14,910,497	$ 57,984,739	$ -	$ 57,984,739
4	Purchased Power Cost Adjustor ("PPCA") Revenue	15,505,234		(15,505,234)	-	-	-
5	Rounding/Reconciling Amount	221		-	221	-	221
6	Subtotal	$ 58,579,697		$ (594,737)	$ 57,984,960	$ -	$ 57,984,960
7	Off System Sales (Third Party Sales)	3,222,980		-	3,222,980	-	3,222,980
8	Subtotal	$ 61,802,677	1	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
9							
10	Other Revenues	$ 606,899		$ -	$ 606,899	$ 260,383	$ 867,282
13	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**		**$ 0**	**$ 76,068,006**	**$ 3,061,529**	**$ 79,129,535**
14							
15	EXPENSES:						
16	Purchased Power	$ 61,802,677	1	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
17	Sub Transmission O&M	169,400		-	169,400	-	169,400
18	Distribution - Operations	2,773,698		-	2,773,698	-	2,773,698
19	Distribution - Maintenance	1,194,657		-	1,194,657	-	1,194,657
20	Consumer Accounting	2,227,246		-	2,227,246	-	2,227,246
21	Customer Service	196,226		-	196,226	-	196,226
22	Sales	96,252		-	96,252	-	96,252
23	Administrative and General	4,756,463	2, 3	662,035	5,418,498	-	5,418,498
24	Depreciation and Amortization	2,239,666		-	2,239,666	-	2,239,666
25	Taxes	-		-	-	-	-
26	Total Operating Expenses	$ 75,456,285		$ 67,298	$ 75,523,583	$ -	$ 75,523,583
27							
28	Operating Margin Before Interest on L.T.- Debt	$ 611,721		$ (67,298)	$ 544,423	$ 3,061,529	$ 3,605,952
29							
30	INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS						
31	Interest on Long-term Debt	$ 2,161,308		$ -	$ 2,161,308	$ -	$ 2,161,308
32	Interest - Other	$ 142,396		$ -	$ 142,396	$ -	$ 142,396
33	Other Dedcutions	$ 17,024		$ -	$ 17,024	$ -	$ 17,024
34	Total Interest & Other Deductions	$ 2,320,728		$ -	$ 2,320,728	$ -	$ 2,320,728
35							
36	MARGINS (LOSS) AFTER INTEREST EXPENSE	$ (1,709,007)		$ (67,298)	$ (1,776,305)	$ 3,061,529	$ 1,285,224
37							
38	NON-OPERATING MARGINS						
39	Interest Income	$ 410,049		$ -	$ 410,049	$ -	$ 410,049
	Gain(Loss) Equity Investments	$ 110,369		$ -	$ 110,369	$ -	$ 110,369
40	Other Margins	$ (32,307)		$ -	$ (32,307)	$ -	$ (32,307)
41	G&T Capital Credits	$ 3,509,969		$ -	$ 3,509,969	$ -	$ 3,509,969
42	Other Capital Credits	$ 107,687		$ -	$ 107,687	$ -	$ 107,687
43	Total Non-Operating Margins	$ 4,105,767		$ -	$ 4,105,767	$ -	$ 4,105,767
44							
45	EXTRAORDINARY ITEMS	$ -		$ -	$ -	$ -	$ -
46							
47	NET MARGINS (LOSS)	$ 2,396,760		$ (67,298)	$ 2,329,462	$ 3,061,529	$ 5,390,991
48							
49							

50 References:
51 Column (A): Cooperative Schedule A
52 Column (B): Schedule CSB-4
53 Column (C): Column (A) + Column (B)
54 Column (D): Schedule CSB-1; Testimony
55 Column (E): Column (C) + Column (D)

Mohave Electric Cooperative, Inc.
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Surrebuttal Schedule CSB-4

SUMMARY OF OPERATING MARGIN ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] PER COOPERATIVE	[B] ADJ #1 Power Revenue, PPCA Revenue, & Purchased Pwr Exp Ref: Sch CSB-5	[C] ADJ #2 Administrative & General Rev & Exp Ref: Sch CSB-6	[D] ADJ #3 Rate Case Expense Ref: Sch CSB-7	[D] STAFF ADJUSTED
	REVENUES:					
1	Margin Revenue (Excludes BCOP Rev & PPCA Rev)	$ 13,658,430	$ -	$ 594,737	$ -	$ 14,253,167
2						
3	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 14,910,497	$ -	$ -	$ 57,984,739
4	Purchased Power Cost Adjustor ("PPCA") Revenue	15,505,234	(15,505,234)	-	-	-
5	Rounding/Reconciling Amount	221	-	-	-	221
6	Subtotal	$ 58,579,697	$ (594,737)	$ -	$ -	$ 57,984,960
7	Off System Sales (Third Party Sales)	3,222,980	-	-	-	3,222,980
8	Subtotal	$ 61,802,677	$ (594,737)	$ -	$ -	$ 61,207,940
9						
10	Other Revenues	$ 606,899	$ -	$ -	$ -	$ 606,899
11						
12	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**	**$ (594,737)**	**$ 594,737**	**$ -**	**$ 76,068,006**
13						
14	***OPERATING EXPENSES:***					
15	Purchased Power	$ 61,802,677	$ (594,737)	$ -	$ -	$ 61,207,940
16	SubTransmission Operation and Maintenance	169,400	-	-	-	169,400
17	Distribution - Operations	2,773,698	-			2,773,698
18	Distribution - Maintenance	1,194,657	-	-	-	1,194,657
19	Consumer Accounting	2,227,246	-	-	-	2,227,246
20	Customer Service	196,226	-	-	-	196,226
21	Sales	96,252	-	-	-	96,252
22	Administrative and General	4,756,463	-	562,035	100,000	5,418,498
23	Depreciation and Amortization	2,239,666	-	-	-	2,239,666
24	Taxes	-	-	-	-	-
25	**Total Operating Expenses**	**$ 75,456,285**	**$ (594,737)**	**$ 562,035**	**$ 100,000**	**$ 75,523,583**
26						
27	**Operating Margin Before Interest on L.T.- Debt**	**$ 611,721**	**$ -**	**$ 32,702**	**$ (100,000)**	**$ 544,423**
28						
29	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
30	Interest on Long-term Debt	$ 2,161,308	$ -	$ -	$ -	$ 2,161,308
31	Interest - Other	142,396	-	-	-	142,396
32	Other Dedcutions	17,024	-	-	-	17,024
33	**Total Interest & Other Deductions**	**$ 2,320,728**	**$ -**	**$ -**	**$ -**	**$ 2,320,728**
34						
35	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	**$ (1,709,007)**	**$ -**	**$ 32,702**	**$ (100,000)**	**$ (1,776,305)**
36						
37	***NON-OPERATING MARGINS***					
38	Interest Income	$ 410,049	$ -	$ -	$ -	$ 410,049
	Gain(Loss) Equity Investments	110,369	-	-	-	110,369
39	Other Margins	(32,307)				(32,307)
40	G&T Capital Credits	3,509,969				3,509,969
41	Other Capital Credits	107,687	-	-	-	107,687
42	**Total Non-Operating Margins**	**$ 4,105,767**	**$ -**	**$ -**	**$ -**	**$ 4,105,767**
43						
44	***EXTRAORDINARY ITEMS***	$ -	-	-	-	$ -
45						
46	***NET MARGINS (LOSS)***	**$ 2,396,760**	**$ -**	**$ 32,702**	**$ (100,000)**	**$ 2,329,462**

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-5

OPERATING MARGIN ADJUSTMENT NO. 1 - POWER REVENUE, PURCHASED POWER COST ADJUSTOR REVENUE, & PURCHASED POWER EXPENSE

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	
1	***Revenue***				
2	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 0	$ 43,074,242	From Line 39
3	Purchased Power Cost Adjustor ("PPCA") Rev	15,505,234	(15,505,234)	-	From Coop Suppl Sch A-1
4	Rounding/Reconciling Amount	221	-	221	
5	**Subtotal BCOP Revenue & PPCA Revenue**	**$ 58,579,697**	**$ (15,505,234)**	**$ 43,074,463**	
6					
7	Staff Recommended Increase To BCOP Rev	-	15,505,234	15,505,234	
8	Staff Recommended Decrease To BCOP Rev	-	(594,737)	(594,737)	From Line 25
9	**Subtotal Revenue**	**$ -**	**$ 14,910,497**	**$ 14,910,497**	
10					
11	Off System Sales (Third Party Sales)	3,222,980	-	3,222,980	From Coop Suppl Sch A-5
12	**Total Revenue**	**$ 61,802,677**	**$ (594,737)**	**$ 61,207,940**	
13					
14	***Expenses***				
15	Purchased Power	$ 61,802,677	$ -	$ 61,802,677	
16					
17	To Remove In House Labor & Benefits	$ -	(120,042)	(120,042)	From JEM-6, P.2
18	To Remove Legal Services	$ -	(335,233)	(335,233)	From JEM-6, P.2
19	To Remove Lobbying Costs	$ -	(32,038)	(32,038)	From JEM-6, P.2
20	To Remove Costs to Prepare Fuel Bank Reports	$ -	(23,015)	(23,015)	From JEM-6, P.2
21	To Remove Consulting Costs	$ -	(83,745)	(83,745)	From JEM-6, P.2
22	To Remove Unsupported Costs	$ -	(664)	(664)	From JEM-6, P.2
23	Subtotal Expenses	-	(594,737)	(594,737)	
24					
25	**Total Expenses**	**$ 61,802,677**	**$ (594,737)**	**$ 61,207,940**	
26					
27	**Operating Margin (Line 18 - Line 30)**	**$ (0)**	**$ 0**	**$ -**	
28					
29		kWh's Subject		kWh's Subject	
30		to PPA in TY	Adjustment	to PPA in TY	
31	Residential Sales	364,970,959	-	364,970,959	
32	Irrigation Sales	4,302,352	-	4,302,352	
33	Small Commercial	113,810,903	-	113,810,903	
34	Large Commercial	171,559,418	-	171,559,418	
35	Lighting	0	-	0	
36	AES Sales	0	-	0	
37	Test Year Sales (In kWhs) subject to PPA	654,643,632	-	654,643,632	
38	Multiplied by: Base Cost of Power per kWh	0.065798000	-	0.065798000	
39	Total Base Cost of Power	$ 43,074,242	$ -	$ 43,074,242	

References:

Column A: Cooperative Supplemental Schedule A-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-6

OPERATING MARGIN ADJUSTMENT NO. 2 - ADMINISTRATIVE AND GENERAL REVENUE & EXPENSE

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED Suppl Sch A1.0	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Administrative and General	$ 4,756,463	-	$ 4,756,463
2	To Reclassify In House Labor & Benefits	-	120,042	120,042
3	To Reclassify Legal Services	-	335,233	335,233
4	To Remove Lobbying Costs	-	-	-
5	To Remove Costs to Prepare Fuel Bank Reports	-	23,015	23,015
6	To Reclassify Consulting Costs	-	83,745	83,745
7	To Remove Unsupported Costs	-	-	-
8	Total Administrative and General	$ 4,756,463	562,035	$ 5,318,498
9				
10				
11				
12		[D]	[E]	[F]
13		Reclassified From Purchased Power Expense		
14		Per Staff		
15		From	Amount	Amount
16		Sch CSB-5	Disallowed	Reclassified
17	To Remove In House Labor & Benefits	$ 120,042	$ 0	$ 120,042
18	To Remove Legal Services	335,233	(0)	335,233
19	To Remove Lobbying Costs	32,038	(32,038)	-
20	To Remove Costs to Prepare Fuel Bank Reports	23,015	0	23,015
21	To Remove Consulting Costs	83,745	-	83,745
22	To Remove Unsupported Costs	664	(664)	-
23		$ 594,737	$ (32,702)	$ 562,035

References:
Column A: Cooperative Schedule A-1
Column B: Testimony, CSB;
Column C: Column [A] + Column [B]

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-7

OPERATING INCOME ADJUSTMENT NO. 3 - RATE CASE EXPENSE

		[A]	[B]	[C]
LINE NO.	**Description**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Rate Case Expense	$ -	$ 100,000	$ 100,000

References:

Column A: Company Schedule C-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF) MOHAVE ELECTRIC COOPERATIVE, INC. FOR) A DETERMINATION OF THE FAIR VALUE OF) ITS PROPERTY FOR RATE MAKING PRUPOSES,) TO FIX A JUST AND REASONABLE RETURN) AND TO APPROVE RATES DESIGNED TO) DEVELOP SUCH A RETURN)	DOCKET NO. E-01750A-11-0136

PUBLIC

DIRECT

TESTIMONY

OF

JERRY MENDL

ON BEHALF OF COMMISSION STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

EXHIBIT
S-6

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EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

The Arizona Corporation Commission ("ACC") secured the services of MSB Energy Associates, Inc. ("MSB"), to evaluate Mohave Electric Cooperative, Inc. ("MEC") power purchases made since July 25, 2001. The purpose of the review is:

- To evaluate MEC's procurement process for power purchases since MEC became a partial requirements customer of AEPCO, identify deficiencies and make recommendations to correct them;

- To determine the prudence of purchases made by MEC since MEC became a partial requirements customer of AEPCO, and make recommendations regarding the prudence of costs allowed for recovery;

- Make recommendations to improve the adjustor mechanism, if necessary and

- Determine the base cost of power.

Conclusions Regarding MEC's Power Procurement Process

Staff concludes that MEC's power procurement process, including MEC's organization and power planning and procurement approaches and policies, are reasonable and appropriate as they pertain to 2010. However, MEC did not provide the information necessary to assess MEC's power procurement process prior to 2010.

Staff recommends that the Commission:

1. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

2. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable.

3. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

Conclusions Regarding the Prudence of MEC's Power Purchases

Staff concludes that MEC included several ineligible costs in its purchased power cost subject to the purchased power cost adjustor in 2010, requiring adjustments in both the test year and in the purchased power bank balance. MEC also failed to provide adequate documentation to justify part of its purchased power costs in 2008 and any documentation to justify its purchased power costs in the July 25, 2001 through December 31, 2006 period. These undocumented costs require adjustments in the purchased power bank balance. MEC began purchasing power from AEPCO under rates that went into effect on January 1, 2011. Those rates may affect dispatch and alter future costs.

Staff recommends that the Commission:

1. Reaffirm that for purposes of the purchased power adjustor, purchased power include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

2. Remove from the 2010 base revenues those costs ineligible for purchased power adjustor treatment that MEC included as purchased power costs in 2010, namely in-house labor costs, consulting costs and legal costs associated with planning and procurement of purchased power.

3. Reduce MEC's purchased power bank balance by $594,737.45 to adjust for the inclusion of these ineligible costs.

4. Determine that the actual eligible purchased power costs were adequately documented in 2007, 2009 and 2010.

5. Disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008, and reduce MEC's purchased power bank balance by that amount.

6. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible and undocumented costs, are prudent and reasonable for 2007-2010.

7. Determine that MEC's objection to providing information prior to 2007 made it impossible to assess whether purchased power costs between July 25, 2001 and December 31, 2006 were prudent and reasonable.

8. Impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and reduce MEC's purchased power bank balance by that amount.

9. Require MEC to file its next rate case no later than April 1, 2016, using a 2015 test year to ensure the purchased power cost data and supporting information remains fresh. MEC may file sooner if necessary.

10. Acknowledge that MEC's selection and management of Western to provide critical services regarding block power and market purchases and sales are prudent and reasonable.

Conclusions Regarding Improvements to MEC's Purchased Power Adjustor

Staff concludes that MEC should be required to file its next rate case no later than April 1, 2016, using a 2015 test year, for prudence review in order to keep information fresh and adjustments current. In addition, Staff concludes that MEC should use the margins on power sales for resale to offset the purchased power costs and be run through the purchased power cost adjustor mechanism.

Staff recommends that the Commission:

1. Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

2. Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

3. Require MEC to file its next rate case no later than April 1, 2016, using a 2015 test year. MEC may file sooner if necessary.

Conclusions Regarding the Base Purchased Power Cost and Purchased Power Bank Balance

Staff concludes that the Commission should set the Base Purchased Power Cost at $0.087701/kWh. Staff concludes that the Commission should adjust the purchased power bank balance to credit ratepayers with $2.704 million.

Staff recommends that the Commission:

1. Adopt a base purchased power cost per kWh of $0.087701/kWh.

2. Adjust the bank balance to credit the ratepayers with $2.704 million, consisting of $594,737 of ineligible costs in 2010, $163,222 of undocumented costs in 2008, and $1.946 million for undocumented purchased power costs in 2001-2006.

3. Direct MEC to adjust the bank balance for any ineligible costs that may have been recovered through the purchased power cost adjustor after December 31, 2010.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jerry E. Mendl. I am the President of MSB Energy Associates, Inc. ("MSB"). My business address is MSB Energy Associates, Inc., 1800 Parmenter Street, Suite 204, Middleton, Wisconsin 53562.

Q. Does exhibit JEM-1 summarize your qualifications?

A. Yes.

Q. What is the purpose of your testimony?

A. I am appearing on behalf of the Arizona Corporation Commission - Utilities Division Staff to address the prudence of Mohave Electric Cooperative, Inc.'s ("MEC" or "the Cooperative") electric power procurement practices since July 25, 2001, the date that MEC converted from full requirements to partial requirements service from Arizona Electric Power Cooperative, Inc. ("AEPCO"). I was charged with the following tasks:

1. To evaluate MEC's procurement process for power purchases since MEC became a partial requirements customer of AEPCO (Addressed in Section 1of my testimony);

2. To identify any deficiencies in MEC's power procurement process and make recommendations to correct those deficiencies (Section 1);

3. To determine the prudence of purchases made by MEC since MEC became a partial requirements customer of AEPCO (Section 2);

4. To make recommendations regarding the prudence of costs allowed for recovery (Section 2);

5. Make any necessary recommendations to improve the adjustor mechanism (Section 3); and

6. Determine the base cost of power (Section 4).

Q. How did Staff conduct its analysis?

A. Staff compiled information primarily through discovery regarding MEC's power procurement procedures and its application of the purchased power cost adjustor. The purpose was to determine whether MEC's organization and power procurement procedures are likely to result in lowest power costs in a changing electricity market. Does MEC: i) regularly review and evaluate all power supply options ii) select reasonable power supply options and iii) modify its plans when circumstances warrant?

In addition to assessing whether MEC had reasonable power procurement procedures in place, Staff also assessed how MEC's purchased power prices compared to the market electricity prices. The purpose was to determine whether MEC was purchasing power at, above or below market prices. Market prices are a reasonable benchmark for prices that would be deemed prudent. This provides insight on how well MEC's power procurement procedures are working – not only whether reasonable organization and procedures exist but also how they are implemented.

Staff looked at both the procurement procedures and market price benchmark for the 2010 test year. This is the most current historical year for which information is available and is a reasonable indicator of expectations for the future. Staff assessed the prudence of MEC's 2010 purchased power costs, identified adjustments to the revenue requirement for purchased power and used that to determine the base purchased power costs.

Finally, Staff assessed the procurement procedures and market price benchmarks to assess whether the purchased power costs for the rest of the 2001-2010 prudence evaluation period were prudent.

SECTION 1: MEC'S PROCUREMENT PROCESS FOR POWER PURCHASES

Q. What elements should the Commission consider in determining whether MEC's power procurement process is appropriate?

A. The purchased power procurement process comprises institutional and implementation factors. Institutional factors pertain to the organizational structure as it applies to power planning and purchases. Implementation factors focus on the development and execution of appropriate procedures for procuring purchased power.

CRITERIA FOR STRUCTURE AND POWER PROCUREMENT PROCEDURES

Q. What elements should the Commission consider in determining whether MEC is appropriately organized to procure power efficiently and economicially?

A. An appropriate structure should clearly define who has the authority to make decisions about power supplies and purchases. These decisions should include integrated resource planning decisions to determine whether MEC should build or purchase power plants, initiate demand response programs, initiate energy efficiency programs, purchase power from designated power plants, purchase power from the regional spot market, or some combination of these resource options. These decisions will also encompass the volumes of each resource to be acquired, based on need, cost, reliability and risk factors.

An appropriate structure will also clearly indicate the limits on that authority. It may be appropriate for low cost, low volume, low risk resource acquisitions to be addressed at lower levels in the organization, with increasingly higher levels of approval required as the decisions increase in terms of potential impacts.

An appropriate structure will also provide checks and balances to ensure that no single individual has excessive authority and to ensure that potential abuses would be discovered on a timely basis.

Q. What elements should the Commission consider in determining whether MEC has implemented appropriate power procurement procedures?

A. Appropriate implementation of power procurement starts with a well-defined statement of objectives. To achieve these objectives, power procurement procedures ideally should be formally written and documented. Ideally, top-level management should adopt these written formal procedures to ensure that the procurement procedures are given high priority by those who are responsible for implementing them. At a minimum, the procedures, even if not formally adopted by top-management, should be written to provide guidance to and a benchmark for measuring the performance of those responsible for procuring power.

Appropriate implementation of power procurement also requires that the power procurement procedures are communicated to those employees responsible for implementing them. To ensure that all relevant employees are aware of the power procurement procedures, the Cooperative should establish training programs, internal communications, job performance criteria and job performance evaluations.

A method to systematically evaluate progress and results is a key element of an appropriately implemented power procurement procedure. This mechanism should monitor the results of the chosen power procurement approach and compare them to the results had other approaches been used. This mechanism should identify opportunities for improvement and stimulate the Cooperative to be open to changing procedures to improve power procurement performance.

Finally, the power procurement procedure should include a mechanism to update the procedure to incorporate improvements and mitigate deficiencies identified in the monitoring phase. This feedback loop is an important feature of an appropriately implemented power procurement procedure. The updating phase creates the expectation that the Cooperative will change its power procurement procedures when conditions warrant (as identified in the monitoring phase).

ASSESSMENT OF STRUCTURE AND PROCEDURES

Q. What has Staff done to evaluate MEC's organization and implementation of its purchased power procurement process?

A. Staff developed a substantial set of data requests addressing these topics and reviewed responses from MEC. Staff analyzed the responses in the context of the criteria for institutional and implementation factors set forth above.

Q. In Staff's opinion, are MEC's organizational structure and power procurement procedures, as both existed in 2010, adequate and appropriate?

A. Yes, Staff concludes that in 2010 MEC met the criteria that Staff set forth above. In converting from an All Requirements Member to a Partial Requirements Member in 2001, MEC took on additional responsibilities for preparing its own load forecasts; for identifying, evaluating, and implementing resources to serve those demands; and for scheduling and dispatching available resources to optimize day-to-day operations. Nine years after the conversion, MEC has a well-developed, evolved and documented approach in place. Nonetheless, Staff recommends that MEC reconsider one of its general planning criteria because it could unnecessarily limit MEC's access to lower cost power supplies in the future.

Q. Why did Staff conclude that MEC's organizational structure and power procurement procedures were adequate and appropriate for 2010?

A. MEC has a well-conceived organizational structure for power supply planning and power procurement. It has written procedures approved at the highest levels of management that address the criteria Staff set forth above. In response to Staff's third data request, MEC prepared a narrative discussion to accompany the answers to specific questions. The narrative response sets out the fundamentals of MEC's planning process, especially laying out the relationships between MEC and AEPCO (which supplies the majority of the power MEC purchases) and Western Power Administration and, in particular, the Desert Southwest Energy Management and Marketing Office ("Western") (which provides services to meet MEC's loads in a manner to minimize costs and to assess the opportunity to sell MEC's excess to the market). It also lays out the roles of Mohave's staff, consultants and Western in preparing load forecasts; identifying, evaluating and implementing resource options; and day-to-day scheduling and dispatching resources. The narrative response is attached as Exhibit JEM-2 CONFIDENTIAL.

MEC also attached its written "Policy of Power Supply Planning and Implementation" in response to Data Request JM-3.8. This document lays out the responsibilities, authorities and procedures of the MEC Board, MEC management, MEC staff, MEC consultants, AEPCO and Western. It also sets out planning objectives, monitoring and feedback to improve the planning and power procurement process, and reporting requirements. MEC's "Policy of Power Supply Planning and Implementation," is attached as Exhibit JEM-3 CONFIDENTIAL. This policy was accepted by MEC's Board on June 18, 2009.

Each criterion that Staff raised has been satisfied for 2010 in the documentation provided by MEC. The following is a reference to the section of MEC's procurement policy that addresses each criterion:

- Clearly define who has the authority to make decisions about power supplies and purchases. MEC has defined the decision-making authority, primarily at the CEO level, with required reporting to the Board. For some major decisions, such as building or purchasing power plants, the Board is ultimately responsible for decisions. Pursuant to its agreement with Western, Western has been assigned specified duties. This is addressed in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, especially in Sections I, II and III and in response to Staff data request JM-3.28 (attached as Exhibit JEM-4).

- Clearly indicate the limits on that authority. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section III.

- Provide checks and balances to ensure that no single individual has excessive authority and to ensure that potential abuses would be discovered on a timely basis. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in paragraphs 7-9 in the Risk section on page 5 of the policy and in Section IV.

- Well-defined statement of objectives. MEC has described the planning objectives in the narrative and attachments to the narrative and in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, especially in Sections II and III.

- Written and documented formal power procurement procedures adopted by top-level management. MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in its entirety is accepted by the Board and generally directs the CEO to implement the policies and procedures. The policies are written and adopted and enforced at the highest levels.

- Communication of power procurement procedures to those employees responsible for implementing them. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section IV.

- Method to systematically evaluate progress and results to identify opportunities for improving power procurement performance. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section V.

- Mechanism to update the procedure to incorporate improvements and mitigate deficiencies identified in the monitoring phase, the expectation that MEC will change its power procurement procedures when conditions warrant. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section VI.

In addition, the Cooperative Board specified in more depth the analyses and information it requires from the CEO and MEC management. It also directed Management to advise the Board at least annually, or more frequently if appropriate, regarding these issues and analyses. See the Exhibits attached to MEC's "Policy of Power Supply Planning and Implementation" (beginning at page 15 of the policy document, Exhibit JEM-3 CONFIDENTIAL). The Board also specified a list of questions regarding "policy parameters of responsibility in implementation and oversight" (pages 19-20 of MEC's policy document, Exhibit JEM-3 CONFIDENTIAL) the answers to which are to be included in the Management's annual, or more frequent, report to the Board.

All of these actions by MEC and its Board indicate that MEC has a well-thought out, well-documented, comprehensive power planning and procurement process that is approved at the highest levels in place in 2010. It fulfils the criteria Staff has previously set forth.

Q. Staff concludes that MEC has appropriate organization and power procurement procedures for 2010. What conclusions has Staff reached regarding MEC's organization and power procurement procedures since MEC became a partial requirements member in July 2001?

A. Staff cannot conclude that MEC's organization and power procurement procedures were appropriate prior to 2010. Staff was unable to obtain the information needed to perform that assessment. Staff requested information concerning the evolution of MEC's organization and power procurement in the Staff's Third Data Request. MEC responded by objecting to providing information prior to 2007. In MEC's narrative (Exhibit JEM-2 CONFIDENTIAL, page 1), MEC states:

> As a result, review of Mohave power purchasing between 2001 and 2008 has little or no relevance to the test year and the projected conditions – the only periods relevant to the current rate proceeding. The foregoing, coupled with the burdensome nature on Mohave of requesting it to review a decade of records, back to 2001, resulted in Mohave objecting to data requests seeking information prior to 2007.

In response to specific questions regarding MEC's organization and power procurement procedures, MEC's responses often suggested that the guiding principles reflected in the 2010 power supply planning and implementation process have not changed since MEC became a Partial Requirements Member in 2001. However, MEC's responses also suggested that its 2010 approach was the result of continuous evolution. Exhibit JEM-5 consists of MEC's responses to Staff Data Requests JM-3.18, 3.19, 3.20, 3.27, 3.29, 3.30 and 3.31. Thus it is impossible for Staff to conclude with any certainty the nature of the organization and procurement process prior to 2010. Staff suspects that it has only recently reached its current levels of sophistication.

Q. Since Staff did not receive any documentation of MEC's organization and procurement policies prior to 2010, why does Staff think that the 2010 approaches are a recent development?

A. There are three reasons. First, the 2010 power procurement policy was not accepted by the Board until June 18, 2010, based on a draft produced in April 2010. See Exhibit JEM-12 CONFIDENTIAL, page 1. The April 2010 draft addressed many points that were raised in the context of the Commission's review of the Sulphur Springs Valley Electric Cooperative's ("SSVEC") performance after becoming a Partial Requirements Member in 2007. Many of the questions and issues addressed in MEC's "Policy of Power Supply Planning and Implementation" are verbatim copies of the Staff data requests in the SSVEC case which were proffered in December 2008 and in the subsequent Staff testimony filed in February 2009. Thus, it appears that some of MEC's current organizational and procedural elements were identified in the SSVEC case a few months earlier.

Second, MEC indicates that there had not been a formal written policy statement when MEC became a Partial Requirements Member (See MEC's response to JM-3.19, which is attached in Exhibit JEM-5). Having a formal written policy provides clear guidance to personnel implementing the policy and creates more reliable benchmark by which to assess performance. Lacking a written policy, Staff would find MEC's power planning and procurement approach problematic.

Third, since MEC agreed to provide information covering the 2007-2010 time frame, it would have provided a written policy and documentation that Staff requested, to the extent that it existed after January 1, 2007. Staff's questions typically requested a description of the current practice, the practice as it existed when MEC became a Partial Requirements

Member in 2001, and any updates or amendments Mohave made between July 2001 and the present. See for example Staff Data Request JM-3.20, attached in Exhibit JEM-5.

These facts lead Staff to believe that prior to June 2009, MEC did not have a documented power planning and procurement policy or procedure. Staff commends MEC for upgrading its policies and procedures regarding power planning and procurement in 2009, to be fully in effect during 2010. However, Staff is unable to determine whether MEC's policies and procedures were adequate prior to 2010, though there is evidence to suggest that they were not written or documented from mid-2001 through mid-2009.

Q. Earlier in Staff's testimony, Staff stated that MEC should reconsider one of its general planning criteria because it could unnecessarily limit MEC's access to lower cost power supplies in the future. Please explain.

A. MEC's power supply plans include purchasing block power and spot market power for the summer months to supplement its available supplies from AEPCO. One of the criteria is to limit the amount of power from the spot market to no more than [redacted] of Mohave's monthly load. Its purpose is to limit the economic risk to MEC of exposure to volatile spot market prices. See the narrative, Exhibit JEM-2 CONFIDENTIAL, at page 6.

In the past two years, spot market prices in the southwest have been stable and quite low as a result of excess capacity regionally and stable and relatively low natural gas prices. Much of the generation on the margin in the southwest region is natural gas fired, often times highly efficient combined cycle units. In Section 2 of this testimony, Staff provides an analysis of market prices at the Mead Hub which clearly demonstrate that spot market prices are currently low and not very volatile.

In 2009–2010, spot market electricity prices were less expensive than the block power MEC purchased, and competitive with the variable cost of power purchased from AEPCO. Thus it is not reasonable to have an arbitrary limit on the amount of lower cost power MEC could procure from the spot market.

MEC did not reach its limit on spot market power in 2010, probably due to MEC's reduced loads during the economic downturn. The reduced loads mean that MEC's allocation of AEPCO resources is able to supply a larger fraction of MEC's energy requirements, resulting in less need for supplemental resources. If MEC's loads increase in the future, MEC will increase its reliance on supplemental resources. If natural gas prices remain stable and at current levels, the least expensive supplemental resource may well be the electricity spot market. It would thus behoove MEC to reconsider its arbitrary limit on the amount of spot market electricity it purchases to take advantage of potentially lower cost opportunities in the future and modify its policies of power supply planning and implementation accordingly.

RECOMMENDATIONS REGARDING STRUCTURE AND PROCEDURES

Q. What are Staff's recommendations regarding MEC's organization and power planning and procurement approaches and policies?

A. Staff recommends that the Commission:

a. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

b. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable.

c. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

SECTION 2: PRUDENCE OF MEC'S POWER PURCHASES

Q. Staff concludes that MEC had reasonable and appropriate organizational structure and procurement procedures as they relate to power purchases. From that, can Staff conclude that MEC made power purchases at reasonable costs?

A. No. Effective organizational structure and procurement procedures would increase the likelihood that MEC would make appropriate purchases and decrease the likelihood of error and abuse. They do not guarantee appropriate purchases at reasonable cost.

Q. What should the Commission consider in determining whether MEC made power purchases at reasonable cost?

A. First, the Commission should consider whether the purchased power costs recorded by MEC are actually for purchased power. If not, the costs recovered through the base purchased power rate and the purchased power adjustor should be adjusted to include only the costs of purchased power.

Second, the Commission should consider whether the actual purchased power costs are reasonable and appropriately documented. This would be done by auditing the costs, ensuring that the costs were documented by appropriate invoices or receipts, and ensuring that the costs were market-based (e.g., determining whether the power purchases were with affiliated interests or subject to "sweetheart" deals).

Finally, in a competitive market, comparing prices paid to market prices is a way to measure whether the prices paid (and cost) were reasonable. The most appropriate way to compare MEC's purchases to market prices is on a marginal basis. That is, at any given time, Staff would analyze how MEC's marginal cost of supply compared to the market price at that time.

INELIGIBLE COSTS

Q. Regarding Staff's first point, did Staff conclude that all of the costs MEC recorded for recovery through the purchased power adjustor in 2010 were legitimate purchased power costs?

A. No. Upon careful review of the costs MEC proposed to recover as purchased power costs through the adjustor and base rates, MEC included significant ineligible costs among the purchased power cost in 2010 for staff and labor cost, consulting cost and legal cost. Please refer to the attached Exhibit JEM-6 CONFIDENTIAL for a breakdown of the costs that are ineligible for recovery through the adjustor. The purchased power bank balance for should be reduced by $594,737.45 to adjust for these 2010 ineligible costs.

MEC included $23,014.78 in its purchased power costs that was recorded as "Other (Fuel Bank Reporting)." This amount is for the services of a consultant to prepare the monthly fuel bank reports. It is not purchased power or the related transmission costs.

MEC included $571,722.67 in its purchased power costs that was recorded as "Other Expenses (Consultants, Employees and Legal)." Of that, $120,041.97 was for MEC's in-house staff labor and fringes. Please refer to the attached Exhibit JEM-7 CONFIDENTIAL for a breakdown of MEC's in-house labor costs. $335,233.34 was for legal services. An additional $32,037.96 was for lobbying services. The technical consultants provided services costing $83,745. Lobbying services, legal services, consulting and in-house payroll costs are not purchased power or the related transmission costs.

Q. Why are these costs ineligible to include in the purchased power costs?

A. They are not purchased power costs and should not be included in the purchased power adjustor clause. As a ratemaking principle, fuel and purchased power clauses are reserved for volatile price changes that are outside the control of the regulated utility. Costs such as consulting and lobbying and legal fees and in-house labor are within the utility's control and are recovered through the general rates.

The Commission observed these principles in July 2001 when deciding upon the restructuring of AEPCO to authorize MEC to become a Partial Requirements Member. In Decision No. 63868 in Docket No. E-01773A-00-0826, the Commission addressed the purchased power and fuel adjustor clause. See Exhibit JEM-8.

> 45. The fundamental rationale for a fuel adjustment clause is that fuel prices can ***change radically based on the overall energy market***...(Emphasis added)
>
> 46. Purchased power and fuel adjustor clauses for Arizona utilities may be created and set during a rate case wherein a base cost of ***fuel and purchased power*** is determined and included in base rates...(Emphasis added)

It is Staff's understanding that the Commission has not modified its straightforward approach of allowing only fuel and purchased power costs to be recovered through an adjustor. The Commission has not taken any action to allow labor, consulting, legal, lobbying and other costs potentially associated with fuel or purchased power to be included in the fuel and purchased power adjustors.

Q. Has MEC recovered in-house labor, consulting, lobbying and legal fees through its adjustor since becoming a partial requirements member in 2001?

A. No. MEC had incurred those kinds of costs since becoming a Partial Requirements Member in 2001, but had not recorded them as purchased power costs. In response to Data Request JMM-7.15, which is attached as Exhibit JEM-9, from 2001 through 2007, labor expenses were not booked as purchased power costs. In 2008, MEC began booking them as purchased power costs, but did not attempt to include them in the purchased power adjustor until 2010.

In response to Data Request JMM-7.16, which is attached as Exhibit JEM-10, from 2001 through 2008, consulting and legal expenses were not booked as purchased power costs. In 2009, MEC began booking some of them as purchased power costs, but did not attempt to include consulting and legal expenses in the purchased power adjustor until 2010.

Exhibit JEM-11 is the response to Data Request JM-4.14. This provides the breakout by the type of expense, the year and month it was incurred, and whether it was recovered from the purchased power adjustor. Again, it demonstrates that MEC was incurring these labor, consulting and legal costs, but did not attempt to recover them through the purchased power adjustor until 2010.

Q. Was there any doubt in MEC's interpretation of the commission's intent in the 2001 order regarding the costs that could be recovered through the purchased power adjustor?

A. No, it appears that there was no doubt for eight years after the order in Docket No. E-01773A-00-0826 that labor, consulting, lobbying and legal costs were ineligible for recovery through the purchased power adjustor. Otherwise, MEC would have attempted recovering them as early as 2001. Since the Commission did not revise its definition of eligible costs for MEC or any other utility, MEC's attempt to unilaterally change the definition should be rejected.

Q. Did MEC include any other ineligible costs in its purchased power adjustor during the audit period 2001 through 2010?

A. Not for the years 2007 through 2010. MEC provided the documentation supporting the purchased power costs included in the purchased power adjustor for 2007 through 2010. All of the costs included by MEC (other than the in-house, consulting, lobbying and legal costs in 2010 discussed above) were eligible purchased power costs.

Staff is unable to reach a conclusion regarding potential ineligible costs included in the purchased power adjustor for the years 2001 through 2006. MEC refused to provide any data regarding the purchased power adjustor or costs it comprised for the years 2001 through 2006 because MEC felt that information was irrelevant to this docket. Thus, Staff was unable to perform the detailed audit of the 2001 through 2006 purchased power costs.

APPROPRIATE DOCUMENTATION

Q. Regarding Staff's second point, did Staff conclude that the eligible purchased power costs are reasonable and appropriately documented in 2010?

A. Yes. All of the eligible purchased power costs going into the purchased power adjustor mechanism and into the energy bank are supported by invoices or documentation from MEC. The invoices are from entities that are either arms length parties at market rates (e.g., Western, PowerEx) or are subject to regulated rates (e.g., AEPCO, Southwest). MEC provided invoices and other documentation to support all of the eligible costs MEC included in its 2010 purchased power adjustor. As stated above, labor costs, consulting costs, lobbying costs and legal costs are not eligible for recovery through the purchased power adjustor and Staff has excluded them from the purchased power costs. As can be seen in Exhibit JEM-6 CONFIDENTIAL, page 2, some of the ineligible costs were not appropriately documented, but these are not part of the base purchased power or purchased power adjustor calculations. No adjustments to the eligible 2010 purchased power costs are required due to non-competitive arrangements or inadequate documentation.

Q. Did Staff also conclude that the actual purchased power costs are reasonable and appropriately documented in the rest of the audit period, 2001 through 2009?

A. No. For the period 2001 through 2006, MEC did not provide any information regarding purchased power costs, the quantity and cost of power purchased, from whom, or under what terms. Therefore, Staff is not able to conclude that the purchased power costs recovered by MEC through the purchased power adjustor in 2001 through 2006 are reasonable. Whatever costs MEC included are clearly not documented.

MEC provided detailed purchased power information and documentation for the years 2007 through 2010. For 2007, 2009 and 2010, the information and documentation was in order and Staff was able to conclude that the purchased power costs MEC recovered through the purchased power adjustor were reasonable and are supported by invoices. In 2007 and 2009, like 2010, the invoices are from entities that are either arms length parties at market rates or are subject to regulated rates. MEC provided invoices and other documentation to support all of the eligible costs MEC included in its 2007 and 2009 purchased power adjustors.

MEC did not provide invoices to support all of its purchased power costs for 2008 for the firm transmission services. This information was not supplied in response to data request JM-3.48, which requested all supporting documents that were used to establish the purchase price. It was not provided in response to data request JMM-7.8, which requested all invoices missing from the information provided in response to JM-3.48. It was not provided in response to data request JEM-9.14, which identified the specific months and expenses for which invoices were missing. Exhibit JEM-12 shows the data requests identified above.

Q. How much of the 2008 purchased power cost included by MEC in its purchased power adjustor was not supported by invoices or other reasonable documentation

A. Although MEC provided many invoices to support its reported purchased power cost in 2008, MEC did not provide the invoices to support $163,221.69 for the firm transmission services provided by WAPA for the months of June through November. Please refer to Exhibit JEM-13 CONFIDENTIAL. The purchased power and fuel adjustor bank balance report should be adjusted with a $163,221.69 credit to ratepayers to refund the unsupported expense recorded in 2008.

COMPARISON OF MEC'S COSTS TO MARKET PRICES

Q. Regarding Staff's third point, how did MEC's purchased power costs compare to market prices?

A. From 2001 through mid-2008, MEC's average purchased power cost compared favorably with regional market prices. Since mid 2008, MEC's average purchased power cost remained quite stable, while the market prices dropped substantially. MEC's average power costs since mid-2008 are significantly higher than regional market prices.

Q. What analysis did Staff perform to conclude that MEC's average costs were comparable to market prices through mid-2008, but have since been above market prices?

A. Staff compiled detailed purchased power cost information provided by MEC in response to JM-7.8 for 2007-2010 (See Exhibit JEM-12, page 2) and unverified purchased power cost information from Staff for 2001 through 2006. The Staff information was a compilation of monthly purchased power adjustor reports submitted to the Commission by MEC, but did not necessarily include the revisions that often accompany these filings or the supporting information to verify the reported numbers. Staff then removed the transmission costs from each of these monthly purchased power costs to determine an average monthly electricity commodity cost.

Staff then took the Mead hub monthly on-peak and off-peak electricity index prices provided by MEC in response to Staff data request JM-3.64 (attached as Exhibit JEM-14 CONFIDENTIAL). Because MEC purchases power from AEPCO and block power suppliers based on an average price that is in effect for the entire month or more, MEC does not face on-peak and off-peak price signals. However, one would expect that MEC's average price should in theory lie somewhere between the Mead off-peak and the Mead on-peak prices if MEC's average costs are competitive with market prices.

Figure Mendl Direct 1 CONFIDENTIAL summarizes the result of that analysis. Also, see Exhibit JEM-15 CONFIDENTIAL, pages 1 and 2. The analysis shows MEC's average monthly purchased power cost, excluding transmission, generally tracking Mead on-peak/off-peak price trends, although not always falling directly within the off-peak to on-peak price range (the shaded area in Figure Mendl Direct 1 CONFIDENTIAL and Exhibit JEM-15 CONFIDENTIAL, pages 1 and 2).

Figure Mendl Direct 1 CONFIDENTIAL

[redacted]

AEPCO PURCHASES

Q. Is Staff concerned that MEC's average cost of purchased power does not exactly track the market prices?

A. It does not surprise Staff that MEC's average costs do not exactly track market prices – MEC's average costs lag AEPCO's production costs by up to six months due to the biennial operation of AEPCO's fuel and purchased power adjustor. AEPCO's production costs would be more likely to track the market than AEPCO's approved rates with its fuel and purchased power adjustor, but MEC's price is the approved rate with the lags. In addition, AEPCO's prices (which are a significant portion of MEC's costs) are based on average cost of service, while market prices are based on marginal cost of service.

Q. Does the fact that MEC's average cost of purchased power is significantly above the market price since mid-2008 mean that MEC purchased power imprudently?

A. No, MEC owns and pays for its member share of AEPCO capacity through fixed charges and demand charges. In effect, those are sunk costs that MEC is obligated to pay irrespective of the amount of energy that Western dispatches from those resources. MEC is under contract to receive the AEPCO resources through 2035, or until the resources are retired. In light of those sunk costs, the appropriate cost minimization strategy is to minimize the variable cost.

MEC's planning and procurement strategies rightly call for the minimization of variable costs. These strategies include monitoring the markets to determine whether there are resources available that cost less than the variable cost of MEC's existing resources. A determination is also made as to whether market prices are above the variable cost of MEC's existing resources, which represents an opportunity for MEC to sell any excess power it may have available from its existing resources. In other words, MEC has procedures for optimizing MEC's portfolio of resources by minimizing variable costs and maximizing the sales of power in excess of MEC's needs.

Q. One would expect that MEC's variable costs would be at or below the market power price if MEC was minimizing its costs. How does the MEC's variable cost of purchased power compare to the market price?

A. Figure Mendl Direct 2 CONFIDENTIAL (also Exhibit JEM-15 CONFIDENTIAL, page 3) shows that AEPCO's variable price component, which is the dominant driver of MEC's variable cost, was less than market prices for the period January 2007 through mid-2008, and has been approximately at market prices from mid 2008 through December 2010. This suggests that MEC's purchased power from AEPCO is near market prices, even after the natural gas prices dropped in mid-2008. Prior to that, higher natural gas prices kept electric market prices, which are largely based on natural gas fired generation, higher than AEPCO's variable price. Based on this, Staff concludes that MEC's purchased power strategy relying on AEPCO for the majority of its supply has been prudent and reasonable, at least for the 2007-2010 period for which Staff had detailed information.

Figure Mendl Direct 2 CONFIDENTIAL

[redacted]

COMPARISON OF MEC'S BLOCK POWER COSTS TO MARKET PRICES

Q. MEC's power planning and procurement strategy also relies on supplementing AEPCO power with block purchases in the peak summer months. How did these block purchases compare in price to market prices and AEPCO's prices?

A. The average cost per kWh of MEC's block power purchases was generally above the Mead market prices and often above MEC's average cost per kWh during the period January 2007 through December 2010. Of the 21 block purchase contract months during this period, 13 were above MEC's average cost. Only four were at or below the corresponding on-peak price at Mead. Exhibit JEM-15 CONFIDENTIAL, page 4, is a graph depicting the block purchases in comparison to MEC's average cost of purchased power and Mead market prices.

Q. Were MEC's block power purchases made above market prices imprudent?

A. Probably not. Imprudence is a possible explanation, but there are other plausible explanations that cannot be ruled out. First, Mead market prices, especially during periods of adequate or excess capacity, probably reflect little capacity value, i.e., under those circumstances Mead prices mostly recover energy costs with a small margin for the seller.

In contrast, when MEC is seeking block power, it is seeking capacity with a relatively low load factor. The products are different and may be priced differently.

Second, block power is an on-peak resource. One would expect that its cost per kWh would be higher than MEC's average costs, since the average cost includes the lower prices associated with off-peak hours.

Third, the nature of the block power purchase contract can also affect its average cost per kWh. If the contract requires MEC to purchase capacity, but not energy, the capacity cost – a sunk cost - may be spread over fewer kWhs, with the effect of inflating the average cost per kWh. If the contract requires MEC to purchase capacity and a fixed block of associated energy, then this on-peak service is higher than average price service.

[redacted]

[redacted]

[redacted] Staff concludes that MEC's actions regarding power purchases are prudent and reasonable. Although the block purchased power prices are somewhat higher than the aggregate market price, the differences may be explained by the differences in products (capacity versus spot market energy).

Q. How much block power did MEC utilize in its resource portfolios?

A. MEC's block power supplies comprised [redacted] of MEC's total purchased power resources in 2010. It was [redacted] in 2007, [redacted] in 2008 and [redacted] in 2009. MEC's response to Staff data request JMM-7.21, which is attached as Exhibit JEM-16 CONFIDENTIAL, provides additional information on MEC's purchased power resources for 2007 through 2010.

In contrast, AEPCO comprised [redacted] of MEC's purchased power in 2007 and 2008, [redacted] in 2009 and [redacted] in 2010. Staff's conclusion is that block power purchases do not substantially affect MEC's overall purchased power cost.

Q. How does the response to JMM-7.21 compare to Staff's analysis as presented in exhibit JEM-15 confidential?

A. MEC's response, attached as Exhibit JEM-16 CONFIDENTIAL is consistent with Staff's analysis. MEC provided data showing the power purchased from AEPCO being less expensive, on average, than block power purchases or power purchased from the market (AES purchases) in 2007-2008. In 2009-2010, power from AEPCO was still less expensive than block power purchases, but more expensive than market purchases.

PRUDENCE PRIOR TO 2007

Q. What has Staff concluded about the prudence of MEC's purchased power costs between July 25, 2001 and December 31, 2006?

A. Nothing. As described earlier in Staff's testimony, MEC objected to providing information prior to 2007. See MEC's narrative (Exhibit JEM-2 CONFIDENTIAL, page 1). Therefore Staff can make no determination regarding the prudence of MEC's power purchases prior to 2007. With MEC being unwilling or unable to provide the information needed to assess the prudence of MEC's power purchases prior to 2007, the options are limited.

Q. What options does the Commission have available to address the prudence of MEC's purchased power costs between July 25, 2001 and December 31, 2006?

A. The Commission could direct MEC to file the needed information, but it is likely that the requisite information is no longer available. Even if MEC provided its purchased power information, it would also have to reconstruct the context of the market and other parameters in that time period. Doing this option would be at best time consuming and burdensome, if even possible.

The Commission could give a "free pass" to MEC. That is, the Commission could accept as prudent those costs that MEC asserted to be prudent during the July 25, 2001 through December 31, 2006 time frame. The drawback to this is that it sends a signal that a utility can avoid scrutiny by failing to maintain records and file requested information.

The Commission could impose a 1% prudence adjustment and accept 99% of the purchased power costs for the July 25, 2001 through December 31, 2006 time frame. This would be because MEC failed to maintain and provide the information to support the prudence of its purchased power.

The Commission could require MEC to file a rate case with purchased power prudence review no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapses between this rate case and the next rate case to ensure the purchased power cost data and supporting information remain fresh. In addition, require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided in its next rate case filing; Staff could recommend that any undocumented and/or unverified costs be returned to the ratepayers including interest or that the purchased power adjustor be eliminated.

Q. How much would the 1% prudence adjustment between July 25, 2001 and December 31, 2006 affect MEC's purchased power bank balance?

A. The unverified purchased power costs reported to the Commission Staff and the resultant prudence adjustment are as follows:

Period	Purchased Power Cost	1% Prudence Adjustment
Aug-Dec, 2001	12,435,419	124,000
2002	31,326,701	313,000
2003	32,195,488	322,000
2004	35,724,426	357,000
2005	35,820,510	358,000
2006	47,178,730	472,000
TOTAL	194,681,274	1,946,000

The 1% prudence adjustment would reduce MEC's purchased power bank balance by $1.946 million, i.e., ratepayers would receive a credit of that amount

THIRD PARTY SALES

Q. Do MEC's sales to third parties generate a profit for MEC?

A. Not always. There are times when MEC sells excess capacity to third parties at a loss. At other times, third party sales result in profits. In addition to losses on third party sales, MEC may also at times incur a lost opportunity, that is, to fail to make a sale that would have resulted in a profit.

Both losses on sales and lost opportunities to sell at a positive margin are detrimental to MEC's ratepayers. Yet under the approaches in place through 2010, either of these outcomes could occur (as well as the positive outcome of making a sale for a positive margin).

Q. PLEASE EXPLAIN.

A. The problem is due to the AEPCO pricing structure in effect through 2010. Under this structure, AEPCO would charge MEC a fixed fee for its allocated share of capacity, a demand charge, an energy charge for a base rate and a fuel and purchased power adjustor. The Commission set all of these rates, and the adjustor could change twice yearly.

MEC's cost of purchased power at any point in time is based on its demands and those four factors in AEPCO's rate (fixed fee for allocated share of capacity, a demand charge, base rate energy charge and fuel and purchased power cost adjustor). AEPCO's actual cost of producing power to serve MEC at that time may be higher or lower than is covered by the rates it charges MEC. In other words, AEPCO's marginal production cost may not be the same as its energy base plus adjustor rates.

MEC and Western are not aware of AEPCO's marginal production cost when dispatch decisions between alternative suppliers are being made. Whether MEC is interested in selling to a third party or simply trying to decide from whom it should purchase its own energy needs, MEC only knows the rate that AEPCO is charging MEC. MEC knows the regulated rate plus the adjustor in effect at the time the purchase is being made to supply MEC's native load or to dispatch more power from its existing resources to sell to third parties. Normally, knowing your cost at the time you are evaluating your options would be adequate.

However, AEPCO's adjustor ensures that AEPCO ultimately recovers its actual prudent costs. If AEPCO's marginal production costs are above what MEC is paying AEPCO for power, AEPCO's adjustor will increase in a future period, and MEC will pay the difference at some future time. Thus, when MEC (or Western on MEC's behalf) is making decisions whether to purchase more power from AEPCO, it does not know the ultimate actual cost of that power for which MEC will be liable when AEPCO's adjustor is modified to reflect actual costs.

In this way, MEC can engage in what it anticipates will be a third party sale for profit and actually incur a loss. Or it can forego an opportunity to sell power at what it anticipates will be a loss and actually miss an opportunity to sell at a profit.

Q. In Staff's analysis, has Staff found instances where MEC sold power to third parties at an apparent loss?

A. Yes. Staff compared the revenues received from third party sales to the AEPCO rates in effect for each month in the 2007-2009 time period for which data was available. At least one sale for a loss incurred in one month in 2007, two months in 2008, 10 months in 2009, and 10 months in 2010. The total losses from these sales appear to be about $39,000.

Q. Did Staff analyze instances where MEC missed an opportunity to sell power to third parties at a profit?

A. No. Staff had no information that would have permitted Staff to know what opportunities MEC had, and thus was not able to quantify the lost opportunities.

Q. The same types of problems would appear to apply to MEC's decisions whether to purchase energy to meet MEC's native load from AEPCO or another supplier. Did Staff identify any such instances that adversely affected MEC's ratepayers by purchasing power from AEPCO rather than another supplier or visa versa?

A. Staff did not perform such an analysis. It would require having hourly marginal production cost for AEPCO and each alternative supplier.

Q. What can be done to avoid sales for a loss and lost opportunities to sell for a profit?

A. The most direct solution is to dispatch resources on the basis of each source's marginal production cost rather than the rate charged. That would require MEC and Western knowing AEPCO's marginal production costs on an hourly basis. MEC could estimate the cost trends that AEPCO is facing by reviewing AEPCO's monthly fuel and purchased power reports. While it would not provide real time data, it may provide insight into the likely future costs based on historic costs. MEC chose this method prior to and during 2010, as indicated in its response to JMM-7.6, which is attached as Exhibit JEM-17. This method is not particularly useful when AEPCO's fuel and purchased power costs are volatile in that large or unpredictable changes will not be captured by the simple trend analysis.

The Commission mitigated the problem somewhat with modifications to AEPCO's pricing approach. Through 2010, AEPCO charged a Schedule A rate that was based on the costs for a mix of coal and natural gas fired resources to meet MEC's load profile. The volatility of natural gas prices led to an unpredictability in AEPCO's adjustor and hence in the cost responsibility MEC would bear. Starting January 1, 2011, AEPCO began implementing a new rate which is based on base and other (natural gas fired) resources. This results in more predictable rates for base power which is the primary source of power for MEC native load and for sales of excess capacity to third parties. It is anticipated that this will result in better cost information and improved decision-making. However, this is a new approach with which there is little actual experience at this time. The Commission should re-evaluate the efficacy of this approach, which does not eliminate the root problem but reduces the fuel cost uncertainty by better lumping together like cost resources, after more data regarding MEC's experience with it becomes available.

Q. Would the same solutions apply to decisions whether to purchase power to serve MEC's native loads from AEPCO or another supplier?

A. Yes.

RECOMMENDATIONS REGARDING PRUDENCE OF MEC'S POWER PURCHASES

Q. What are Staff's recommendations regarding the prudence of MEC's power purchases?

A. Staff recommends that the Commission:

a. Reaffirm that for purposes of the purchased power adjustor, purchased power includes only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

b. Remove from the 2010 base revenues those costs ineligible for recovery through the purchased power adjustor that MEC has included as purchased power costs in 2010, namely in-house labor costs, consulting costs and legal costs associated with planning and procurement of purchased power.

c. Reduce MEC's purchased power bank balance by $594,737.45 to adjust for the inclusion of these ineligible costs.

d. Determine that the actual eligible purchased power costs were adequately documented in 2007, 2009 and 2010.

e. Disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008, and reduce MEC's purchased power bank balance by that amount.

f. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible and undocumented costs, are prudent and reasonable for 2007-2009.

g. Determine that MEC's objection to providing information prior to 2007 made it impossible to assess whether purchased power costs between July 25, 2001 and December 31, 2006 were prudent and reasonable.

h. Impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and reduce MEC's purchased power bank balance by that amount.

i. Require MEC to file a rate case with purchased power prudence review no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapses between this rate case and the next rate case to ensure the purchased power cost data and supporting information remains fresh. In addition, require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided; Staff may recommend that any undocumented and/or unverified costs be denied including interest or that the purchased power adjustor be eliminated.

j. Acknowledge that MEC's selection and management of Western to provide critical services are prudent and reasonable.

k. Require MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period.

SECTION 3: IMPROVEMENTS TO MEC'S ADJUSTOR MECHANISM

Q. Does Staff have any recommended improvements to MEC's adjustor mechanism?

A. Yes. Staff has three suggestions for the Commission to consider. First, as Staff indicated previously, MEC should be required to submit a rate case no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapse between this rate case and the next rate case. Limiting the amount of purchased power cost not yet subject to prudence review to a maximum of five years of costs would keep the information needed for prudence review fresh and current. It would also avoid surprises of having potential disallowances, especially large disallowances that could accumulate over many years.

Second, Staff noted that MEC does not credit the purchased power costs with the revenues from third party sales, or, more generally, any sales that are not subject to the adjustor rate. MEC's calculation of the adjustor and the bank balance subtracts the cost of power purchased for sales to third parties from the total cost of purchased power. While that yields a net cost of purchased power for retail sales subject to the adjustor mechanism, it does not address what happens to the net revenues from the sales made to third parties and special contracts that are not subject to the purchased power adjustor mechanism. Staff recommends that the Commission require the revenues to offset the purchased power costs.

Q. Please explain in more detail the treatment of margins on third party power sales.

A. When a utility purchases fuel and power to meet its loads, it would argue that those costs are to be recovered from the ratepayers through its energy rates and fuel adjustment clause. When the purchased fuel and power is not fully utilized by its customers, the utility can reduce customer costs by selling the excess fuel and purchased power. The question is what happens to the revenues from the sale of excess fuel and power.

In MEC's approach, it calculates the amount of third party energy sold, calculates its cost of that energy, and reduces the cost of purchased power recovered from ratepayers by that amount. The revenues generated by the sale do not enter the ratepayer purchased power adjustor calculation. Rather these revenues (net of the calculated cost of the power) end up in the member's patronage capital credit account where it is available to fund construction or operations. Refer to MEC's response to Staff data request JEM-8.8, attached as Exhibit JEM-18. Part of MEC's purchased power costs are handled through the purchased power adjustor mechanism and part through other accounts. MEC's approach should indirectly flow margins on third party sales back to MEC's ratepayers. How quickly and to which ratepayers the margins are returned is unclear as it would depend on the cash flow and cash needs at the time.

Another approach is to subtract the revenues from the third party sales from the total cost of purchased power. This approach reduces the purchased power cost by the cost of the power for third party sales (same as the MEC approach) ***and*** the margin on those sales. Thus all of the purchased power costs and margins are handled within the purchased power adjustor mechanism. Margins on third party sales flow immediately and directly to the ratepayers.

Q. Would the same considerations apply to special contract sales, such as LC&I Substation customers that are not subject to the purchased power adjustor?

A. Yes, it is Staff's understanding MEC's special contract with an LC&I substation customer has terminated and that there are currently no special contract sales or plans for new special contracts.

Q. How large are the margins that MEC collected on third party sales?

A. The margins vary from year to year. According to MEC's initial filing for a 2009 test year, Schedule F-4.1 (attached as Exhibit JEM-18, page 2), the *projected* margin for third party sales is $309,874.82. Based on MEC's supplemental filing for a 2010 test year, Schedule F-4.1 (attached as Exhibit JEM-18, page 3), the *projected* margin for third party sales is $475,686.89. MEC is proposing revenue requirements and rates based on the 2009 test year. Staff is basing revenue requirements and rates on the 2010 test year. Note that both the 2009 and 2010 margins are based on MEC's expectation that third party sales will increase to 76,313,520 kWh from their actual 2009 and 2010 volumes.

Staff estimated the margins based on actual AES non-jurisdictional sales volumes, costs and revenues in 2007-2010. The margins are stated in Exhibit JEM-19 CONFIDENTIAL. The fact that these actual margins can vary so much based on actual sales volumes, MEC's purchased power costs, and market prices add impetus to including the margins in the purchased power adjustor mechanism.

Q. How can the recommendation that the Commission require the revenues from sales to entities not subject to the purchased power adjustor to offset the purchased power costs be implemented?

A. The method can be implemented simply by subtracting the total revenue from sales to entities not subject to the purchased power adjustor (rather than only the cost of power sold to those entities – the current practice) from the total purchased power cost. Everything else is the same.

Q. In its response to Staff data request JEM-8.8 (attached as exhibit JEM-18), MEC indicates that it included $309,874 in margins from third party sales in its 2009 test year calculations and reduced the requested rate increase by that amount. If the Commission adopts Staff's recommendation, would Staff agree with MEC's adjustment to increase the requested rate increase by that amount?

A. In principle, yes. If the Commission adopts Staff's recommendation, the margins would no longer contribute to the member's patronage capital credit account. Thus, MEC's requested rate increase would need to be increased by the amount of MEC's estimated margins from third party sales, which had previously offset general revenue requirements and under Staff's proposal would instead offset purchased power costs. According to MEC's calculations, the Commission should remove $309,874 based on the 2009 test year. It should remove $475,687 based on the 2010 test year recommended by Staff. If the Commission adopts Staff's recommendation, the 2010 test year general revenue requirement would be increased by $475,687 to reflect MEC's anticipated reduction in contributions from the margins to the patronage capital credit account. But the purchased power base cost would be decreased by $475,687, bringing MEC to a revenue neutral position with respect to its calculated test year margins.

Since Staff's proposal would flow the margins through the purchased power adjustor, the net power cost would be self correcting for variations in: i) MEC's actual price of purchased power for resale; ii) actual price at which the power was sold; and iii) the volume of sales. If the $475,687 reduction in base purchased power cost understates the margins (such as 2008) the additional credit will flow to MEC's ratepayers. If the $475,687 reduction in base purchased power cost overstates the margins (such as 2009– see Exhibit JEM-19 CONFIDENTIAL), the additional cost will be assessed to MEC's ratepayers.

Under Staff's proposal it is not necessary to predict with accuracy the third party sales margins to include in the base purchased power cost. The adjustor mechanism will self correct for any deviations from the expected. However, since the intent of the purchased power adjustor mechanism is to estimate the base purchased power cost to zero-out the adjustor rate, it would be more appropriate to reduce the base purchased power cost by the expected margins to at least begin with a zero adjustor rate.

In contrast, MEC's method of applying third party sales margins to member's patronage capital credit account means that MEC's earnings could fluctuate greatly depending on the margins on the third party sales market.

Q. Are MEC's estimates of the margins on third party sales, $309,874.82 for test year 2009 or $475,686.89 for test year 2010 reasonable?

A. They are reasonable amounts by which to reduce the base purchased power cost under Staff's proposal because variations from the forecasted margins are self correcting. The issue is more significant for MEC's proposal to set a fixed level of expected margins, which then directly affect its earnings.

The projected margins per kWh calculated by MEC were $0.004061/kWh based on 2009 and $0.006233/kWh based on 2010. (See Exhibit JEM-18) These projected margins are similar to the actual margins that Staff estimated in 2009 and 2010, so both appear reflective of the lower electricity market prices after mid-2008. (See Exhibit JEM-19 CONFIDENTIAL)

However, Staff did not attempt to verify the accuracy of MEC's third party sales margin forecasts to the level that would be required when it affects MEC's overall returns, as it does in MEC's approach. Is it reasonable to expect future third party sales volumes that are 60% more than 2010 actual levels and more than four times the 2009 levels? Is it reasonable to expect that changing AEPCO's pricing will result in increased third party sales? Will it result in less uncertainty in dispatching resources with the result that transactions will occur at lower thresholds of minimum benefits, i.e., that MEC can get a reasonable probability of a positive margin even with smaller expected margins on individual transactions? Will the result be more sales at lower margins? These questions cannot be answered until there is an adequate base of experience with the new dispatch opportunities under AEPCO's new pricing strategy which went into effect in January 2011.

RECOMMENDATIONS REGARDING IMPROVEMENTS TO MEC'S ADJUSTOR MECHANISM

Q. Please summarize Staff's recommendations regarding improvements to the purchased power adjustor mechanism.

A. Staff recommends that the Commission:

a) Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

b) Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

c) Require MEC to file its next rate case no later than April 1, 2016, using a test year of 2015. MEC may file sooner if necessary.

SECTION 4: MEC'S BASE COST OF POWER

BASE POWER COSTS

Q. What period did Staff use to establish the base cost of power?

A. Staff used calendar year 2010 to determine the base cost of purchased power: 2010 is the most current year for which data were available.

Q. Will 2010 be representative of the base power costs in future years?

A. It is the best information currently available, but it may not be representative of purchased power in 2011 and beyond. The reason is that the Commission approved a new rate for AEPCO which went into effect on January 1, 2011. The new rate modifies the pricing structure under which MEC purchases power from AEPCO in that after 2010, base resources are plants with similar cost characteristics. Other resources are likewise grouped with similar cost characteristics. Under the rates in place through 2010, base resources included a slice of resources with differing cost characteristics, which made it more difficult to predict operating costs for which MEC would ultimately be liable through AEPCO's fuel clause. To avoid entering transactions that would result in economic loss to MEC, MEC adopted a conservative approach to power sales to third parties, and instructed Western to dispatch resources accordingly.

As a result of AEPCO's new rate structure to reduce cost uncertainty, MEC may be able to dispatch its resources differently, thus affecting overall purchased power costs. At this point, it is unclear how large the effect of changed dispatch will be.

ACTUAL POWER COST IN 2010

Q. What was MEC's actual cost of power in 2010?

A. MEC'S Supplemental filing (Schedule F-5.0, page 2) showed an unadjusted jurisdictional purchased power cost of $52,128,007.66. This cost does not match the unadjusted jurisdictional purchased power costs reported in the supplemental response to Staff data request JM-3.48, where $52,270,355.91 was used to calculate the purchased power bank balances reported to the Commission on form FA-1 in 2010. For the purposes of developing the base purchased power cost, Staff elected to use the Supplemental filing to the application because the Supplemental filing would presumably be MEC's internally consistent information set, whereas the response to JM-3.48 was provided by Guernsey for a different purpose. The response to JM-3.48 was initially delayed because Guernsey discovered that its spreadsheets needed to be updated. Staff anticipates that MEC will reconcile the differences between fuel costs it provided for 2010 and will verify the proper calculation of the bank balance in its rebuttal testimony.

Q. What was MEC's actual sales volume of power subject to the purchased power adjustor in 2010?

A. MEC'S Supplemental filing (Schedule F-5.0, page 1) showed the unadjusted jurisdictional purchased power sales subject to the purchased power adjustor to be 618,974,832 kWh in 2010. This cost does not match the unadjusted jurisdictional sales subject to the purchased power adjustor reported in the supplemental response to Staff data request JM-3.48, where 619,478,531 kWh was used to calculate the purchased power bank balances reported to the Commission on form FA-1 in 2010. For the purposes of developing the base purchased power cost, Staff elected to use the Supplemental filing to the application for the reasons described above. Staff anticipates that MEC will reconcile the differences between sales volumes it provided for 2010 and will verify the proper calculation of the bank balance in its rebuttal testimony.

Q. What was the unadjusted purchased power cost per kwh for 2010?

A. The unadjusted purchased power cost per kWh for 2010 was $0.084217/kWh. The derivation of this value is shown on Exhibit JEM-20 CONFIDENTIAL, page 1. This would be the base purchased power cost to be set in this rate case if the 2010 actual experience was representative of future conditions.

MEC ADJUSTMENTS

Q. What adjustments to the actual 2010 experience did MEC propose to develop the 2010 test year base purchased power costs?

A. The LC&I Substation customers special rate has terminated, meaning that both the costs of power and the volume of power subject to the purchased power adjustor would increase. MEC assumed that the volume of purchases by LC&I Substation customers would remain the same. The net result of this adjustment was to add $2,305,383.70 to the purchased power costs and 35,668,800 kWh to the sales volume subject to the purchased power adjustor.

MEC also recalculated the cost of power purchased from AEPCO under the new rates effective January 1, 2011. This adjustment added $4,146,305.34 to the purchased power costs and 0 kWh to the sales volume subject to the purchased power adjustor.

MEC's third adjustment was to make lighting sales subject to the purchased power adjustor. This adjustment increased the sales volume in 2010 subject to the purchased power adjustor by 1,100,103 kWh.

Q. Does Staff agree with these adjustments to the actual 2010 test year?

A. Yes. The net effect of these adjustments is a base purchased power cost per kWh of $0.089333. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 2.

Staff's calculation to this point is consistent with MEC's. MEC calculated the same power cost per kWh sold in Supplemental Schedule N-2.0, which is attached as Exhibit JEM-21, page 1.

Q. Why is MEC proposing a base purchased power cost per kwh of $0.091183 if its own calculation for 2010 shows it to be $0.089333 per kwh?

A. MEC calculated the $0.091183 per kWh value for the base purchased power cost based on its initial 2009 test year. MEC also decided to adhere to its original proposal based on 2009 even after submitting the 2010 supplemental information because it believed that 2009 remained representative of MEC's current operations. (Searcy Supplemental Direct Testimony, page 6)

Exhibit JEM-21, page 1 shows that using MEC's proposed value for the base purchased power cost developed for a 2009 test year with 2010 test year data will result in a base purchased power that over-collects purchased power costs. As a result, MEC intentionally starts off with a negative purchased power adjustor cost to offset the over-collection rather than beginning with a zero adjustor.

Q. Did MEC make any adjustments to the 2010 test year for third party sales?

A. As previously discussed, MEC increased its third party sales forecast to 76,313,520 kWh. MEC also increased its purchased power cost to $3,222,979.80 to provide a supply for the increased sales volumes. Because MEC treats third party sales as separate from the purchased power adjustor, these changes did not cause any change in the base purchased power costs per kWh. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 3.

Q. How did MEC's revision of the third party sales projections affect the test year revenue requirement, since it did not affect the base purchased power cost and adjustor?

A. As stated earlier, MEC's revision of the third party sales forecast results in a projected margin on the sales of $475,686.89 which is credited to ratepayers outside the adjustor mechanism.

STAFF ADJUSTMENTS

Q. What is the effect on the base purchased power cost of Staff's proposal, discussed in section 2, to remove ineligible costs?

A. The effect of removing $571,722.67 for in-house labor, consulting, lobbying and legal fees and $23,014.78 for consulting on fuel bank reporting is to lower the base purchased power cost per kWh to $0.088426 per kWh. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 4.

The costs that Staff has removed as ineligible for purchased power are not necessarily imprudent. The prudent portions of those costs should be recorded in their proper accounts for recovery through general rates, but not in the purchased power accounts. The

$571,722.67 for in-house labor, consulting, lobbying and legal fees includes [redacted] related to lobbying.

Q. What is the effect on the base purchased power cost of Staff's proposal, discussed in section 3, to include the margins on third party sales in the purchased power base and adjustor calculations?

A. Staff has applied MEC's calculated profit on the third party sales of $475,686.89 as an offset to purchased power costs, thus flowing all third party power sales margins back to the ratepayers quickly and efficiently.

The profits on third party sales reduce the purchased power costs and thus the base cost of purchased power per kWh. The affect on the 2010 test year is to reduce the base purchased power cost per kWh to $0.087701 per kWh. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 5. The removal of the third party margins as a credit to the general rates requires that the general rates be raised accordingly.

Q. What purchased power cost does Staff recommend for setting rates for MEC?

A. All of Staff's recommended adjustments are summarized in Exhibit JEM-22 CONFIDENTIAL.

For the purposes of setting the base purchased power cost, Staff recommends that the Commission use $57,509,272 as the purchased power cost coupled with 655,743,735 kWh of jurisdictional sales.

For the purposes of determining MEC's overall operating costs and operating expenses, the Commission should use $61,207,939 as the purchased power cost (to supply both MEC native and third party sales for resale) coupled with 732,057,255 kWh of total sales.

PURCHASED POWER COST BANK ADJUSTMENTS

Q. Please summarize the adjustments that you recommended to the purchased power cost bank balance.

A. Staff recommends the following adjustment.

- In Section 2, Staff recommends disallowing $594,737.45 in ineligible costs in 2010, the first year that MEC included in-house labor, consulting, lobbying and legal fees in the purchased power costs. Because they were recovered improperly through the purchased power adjustor, it is necessary to adjust the bank balance by that amount to return the money to the ratepayers.

- ~~In Section 2, Staff also recommends disallowing $163,221.69 for firm~~ transmission service from WAPA in undocumented purchased power costs from 2008.

- *Finally in Section 2 Staff also recommends* disallowing $1,946,000 as a prudence adjustment for undocumented purchased power costs from August 2001 through December 2006.

Q. Would it not be double-counting the adjustment for in-house labor, consulting, lobbying and legal fees by including it as an adjustment to the purchased power cost bank balance as well as to base 2010 base purchased power cost per kwh?

A. No. The disallowance in 2010 for the ineligible expenses refunds money that was already charged to and accounted for in the bank balances. Making the adjustment to the bank balance reverses the existing error. Adjusting the base purchased power cost for the 2010 test year removes the ineligible expenses and ensures that they will not be collected through the purchased power cost adjustor mechanism in the future.

Q. How would the Commission make the adjustments to the purchased power cost bank balance?

A. I recommend that the Commission make a one time adjustment of $2.704 million to the bank balance to reflect the recommended disallowances. The adjustment should be made to bank balance as of December 31, 2010 as soon as practicable after the order is issued.

A further adjustment would have to be made to remove ineligible costs (in-house labor, consulting, lobbying and legal costs) MEC collected during 2011 and 2012 up to the date of the order.

RECOMMENDATIONS REGARDING PURCHASED POWER COST ADJUSTMENTS

Q. Please summarize your recommendations regarding the base purchased power costs and the adjustments to the purchased power cost bank balance.

A. The Commission should:

1) Adopt a base purchased power cost per kWh of $0.087701/kWh.

2) Adjust the bank balance to credit the ratepayers with $2.704 million, consisting of $594,737 of ineligible costs in 2010, $163,222 of undocumented costs in 2008, and $1.946 million for undocumented purchased power costs in 2001-2006.

3) Direct MEC to adjust the bank balance for any ineligible costs that may have been recovered through the purchased power cost adjustor after December 31, 2010.

SUMMARY OF STAFF'S RECOMMENDATIONS

1. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

2. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable.

3. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

4. Reaffirm that for purposes of the purchased power adjustor, purchased power include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

5. Remove from the 2010 base revenues those costs ineligible for recovery through the purchased power adjustor that MEC has included as purchased power costs in 2010, namely in-house labor costs, consulting costs and legal costs associated with planning and procurement of purchased power.

6. Reduce MEC's purchased power bank balance by $594,737.45 to adjust for the inclusion of these ineligible costs.

7. Disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008, and reduce MEC's purchased power bank balance by that amount.

8. Impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and reduce MEC's purchased power bank balance by that amount.

9. Determine that the actual eligible purchased power costs were adequately documented in 2007, 2009 and 2010.

10. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible and undocumented costs, are prudent and reasonable for 2007-2010.

11. Determine that MEC's objection to providing information prior to 2007 made it impossible to assess whether purchased power costs between July 25, 2001 and December 31, 2006 were prudent and reasonable.

12. Require MEC to file a rate case with purchased power prudence review no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapses between this rate case and the next rate case to ensure the purchased power cost data and supporting information remains fresh. In addition, require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided; Staff shall recommend that any undocumented and/or unverified costs be denied including interest or that the purchased power adjustor be eliminated.

13. Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

14. Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

15. Require MEC to file its next rate case no later than April 1, 2016, using a test year of 2015. MEC may file sooner if necessary.

16. Acknowledge that MEC's selection and management of Western to provide critical services are prudent and reasonable.

17. Require MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period.

18. Adopt a base purchased power cost per kWh of $0.087701/kWh.

19. Direct MEC to adjust the bank balance for any ineligible costs that may have been recovered through the purchased power cost adjustor after December 31, 2010.

Q. Does this conclude your direct testimony?

A. Yes it does.

JERRY E. MENDL
President
MSB Energy Associates

AREAS OF EXPERTISE

- Analysis of energy resource adequacy, cost and availability
- Evaluation of alternative energy resource options
- Analysis of electric utility bulk power supplies
- Analysis of electric utility projected merger savings and implications on system operations and costs
- Transmission system analysis
- Service delivery and markets in a restructured electric utility industry

EDUCATION

1973 B.S. Degree in Nuclear Engineering, With Very High Honors, from the University of Wisconsin, Madison, Wisconsin

1974 M.S. Degree in Nuclear Engineering from the University of Wisconsin, Madison, Wisconsin.

EXPERIENCE

1987-Present
President
MSB Energy Associates, Inc.
Middleton, Wisconsin

Since co-founding MSB Energy Associates in 1988, Mendl has served public-sector clients in Arizona, Kentucky, California, Utah, Nevada, Washington, Texas, Alaska, Iowa, Illinois, South Carolina, Connecticut, Massachusetts, Vermont, Maryland, Michigan, Missouri, Minnesota, Louisiana, Wisconsin, Pennsylvania, Georgia, Hawaii, Ohio, New Jersey, the District of Columbia and Ontario. Much of his recent work has involved electric utility restructuring, low-income consumer energy affordability and service issues, prudence of gas and electric utility planning and purchase practices, and analyzing need for transmission lines. He assesses "green pricing" tariffs for renewable electric resources and fuel/purchase power costs for electric and natural gas utility rate cases and renewable energy alternatives for utility construction cases. He evaluates electric utility restructuring alternatives and prepares restructuring policy recommendations and supporting technical information. He analyzes long-range plans and planning methods used by gas and electric utilities. He prepares and presents reports, recommendations and testimony.

He conducted engineering, environmental, economic and life-cycle cost analyses of alternate energy resource options, including improved end-use energy efficiency and renewable resources. Mendl developed state regulatory commission codes for implementing integrated resource planning and evaluated the adequacy of existing and proposed codes. Mendl was both organizer and presenter for a series of five least-cost planning workshops across the U.S. sponsored by the National Association of Regulatory Utility Commissioners (NARUC). He also participated in five Conservation Law Foundation collaborative projects in the northeastern states.

1974-1988

Administrator, Division of Systems Planning, Environmental Review and Consumer Analysis (1979-1988)
Director, Bureau of Environmental and Energy Systems (1976-1979)
Public Service Engineer (1974-1976)
State of Wisconsin, Public Service Commission
Madison, Wisconsin

Mendl was employed by the Wisconsin Public Service Commission for 14 years (1974-1988), and was responsible for the development and evolution of Wisconsin's long-range planning process for electric utilities. He had overall responsibility for directing the Commission's activities concerning utility long-range plans. In addition, Mendl had overall responsibility for and directed the preparation of environmental impact statements and environmental assessments, identifying expected impacts as well as evaluating alternatives, for five large power plants, numerous transmission lines, a major natural gas pipeline, and many policy issues including Electric Space Heat, Electric Utility Tariffs, Electric Sales Promotion, Small- Power Production and Cogeneration, and Extension of Service. Mendl was also responsible for directing the preparation of major studies, including *The Alternative Electric Power Supply Study, Alternative Electric Power Supply - Update*, and *Utility SO_2 Cleanup - Cost and Capability*. (The *Alternative Electric Power Supply Study* and *Update* identified renewable energy, load management and energy efficiency resources that would economically meet Wisconsin's long term electricity needs.) Mendl testified before the Wisconsin Commission in rate cases, planning cases, construction certificate cases and policy cases. He also appeared before other state Commissions and the Federal Energy Regulatory Commission.

OTHER DISTINCTIONS

Mendl staffed the NARUC Subcommittee on Energy Conservation for two and one-half years, and was closely involved with the preparation of the *Least-Cost Planning Handbook for Public Utility Commissioners.*

Mendl also was appointed to serve a four-year term on the Research Advisory Committee of the National Regulatory Research Institute (NRRI). One of seven regulatory staff selected nationally, Mendl helped NRRI to shape its research agenda to be more useful and responsive to the regulatory community.

Mendl is a Registered Professional Engineer in the State of Wisconsin.

TESTIMONY

Mendl, since co-founding MSB Energy Associates in 1988, has testified in the following proceedings:

Submitted To:	Subject	Docket No.	Date
Nevada Public Utilities Commission	Nevada Power and Sierra Power Energy Supply Plans	11-09003, 11-09004	2011
Nevada Public Utilities Commission	Nevada Power and Sierra Power electric fuel and power and Sierra LDC gas cost recovery practices (DEAAs)	11-03003, 11-03004, 11-03005	2011
Nevada Public Utilities Commission	Nevada Power Energy Supply Plan – gas hedging and electric power sales	10-09003	2010

Nevada Public Utilities Commission	Sierra Pacific Power Integrated Resource Plan/Energy Supply Plan	10-07003	2010
Nevada Public Utilities Commission	Nevada Power and Sierra power electric fuel and power cost recovery practices (DEAAs)	10-03003 & 10-03004	2010
Nevada Public Utilities Commission	Nevada Power and Sierra Pacific Power Energy Supply Plan Update	09-07003 & 09-09001	2010
Wisconsin Public Service Commission	Glacier Hills Wind Park application by WEPCo, analyze cost/benefits and RTO dispatch	6630-CE-302	2009
Nevada Public Utilities Commission	Nevada Power electric fuel and power cost recovery practices (DEAA)	09-02029	2009
Nevada Public Utilities Commission	Sierra Power gas and electric fuel and power cost recovery practices (DEAA)	09-02030 & 09-02031	2009
Wisconsin Public Service Commission	Need analysis for 345 kV transmission line proposed by American Transmission Company	137-CE-147	2009
Arizona Corporation Commission	Sulphur Springs Valley Electric Cooperative power procurement review	E-01575A-08-0328	2009
Nevada Public Utilities Commission	Nevada Power Energy Supply Plan Update	08-08030	2008
Nevada Public Utilities Commission	Sierra Power Energy Supply Plan Update	08-08031	2008
Nevada Public Utilities Commission	Sierra Power gas and electric fuel and power cost recovery practices (DEAA)	08-02043 & 08-02044	2008
Nevada Public Utilities Commission	Nevada Power fuel gas and power cost recovery practices (DEAA)	08-02042	2008
Nevada Public Utilities Commission	Westpac Utilities fuel purchase practices and costs (including merging of utility LPG and natural gas rates)	07-05019 & 07-05020	2007
Nevada Public Utilities Commission	Nevada Power Amendment to 2006 IRP and Energy Supply Plan update forward sales proposal	07-07013	2007
Nevada Public Utilities Commission	Sierra Pacific Power approval of 2007 IRP forward sales proposal	07-06049	2007
Nevada Public Utilities Commission	Southwest Gas fuel procurement practices and setting DEAA rate	07-05015	2007
Georgia Public Service Commission	Georgia Power IRP 2007 demand side management plan, energy efficiency and cost tests	24505-U	2007
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER & DEAA)	07-01022	2007

Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER & DEAA)	06-12001	2007
Arizona Corporation Commission	UNS Gas prudence of gas procurement practices	G-04204A-05-0831	2007
Nevada Public Utilities Commission	Westpac Utilities fuel purchase practices and costs (BTER & DEAA)	06-05016 & 06-05017	2006
Nevada Public Utilities Commission	Nevada Power Integrated Resource Plan - gas purchase strategies	06-06051	2006
Nevada Public Utilities Commission	Sierra Pacific Power Energy Supply Plan - gas purchase strategies	06-07010	2006
Wisconsin Public Service Commission	Strategic Energy Assessment - electrical adequacy through 2012	5-ES-103	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (DEAA)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (DEAA)	05-12001	2006
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14717	2006
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14716	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER)	05-12001	2006
Nevada Public Utilities Commission	Nevada Power gas purchase practices – Energy Supply Plan	05-9017	2005
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices – Energy Supply Plan	05-9016	2005
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14403	2005
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14401	2005
Kentucky Public Service Commission	Analysis of need for and electrical alternatives to EKPC Cranston-Rowan County transmission line	2005-00089	2005
Nevada Public Utilities Commission	Nevada Power gas purchase practices	04-9004	2004
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices	04-7004	2004

Nevada Public Utilities Commission	Prudence of Southwest Gas PGA costs, purchase practices	03-12012	2004
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-13902	2004
Wisconsin Public Service Commission	WPS rate case, low income programs, Weston 4 pre-certification expenses and capital	6690-UR-115	2003
Wisconsin Public Service Commission	Alliant rate case, RiverSide purchase power cost and incentive, Columbia maintenance and outages	6680-UR-113	2003
Wisconsin Public Service Commission	Alliant rate case, RockGen purchase power savings bonus, coal procurement	6680-UR-112	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in WPS rate case	6690-UR-114	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in MG&E rate case	3270-UR-111	2002
Wisconsin Public Service Commission	Assess renewable energy and other alternative resources in WE Power the Future –Port Washington case	05-CE-117	2002
Wisconsin Public Service Commission	Assess costs related to formation and operation of American Transmission Company	05-EI-129	2002
Wisconsin Public Service Commission	Filed comments in investigation of purchase power incentive mechanisms	05-EI-131	2002
Wisconsin Public Service Commission	Alliant rate case, adequacy of planning, purchase power contracts, coal contracts	6680-UR-111	2002
Michigan Public Service Commission	Analyze proposed gas cost recovery factor and plan, and gas procurement practices.	UR-13060	2002
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-113	2002
Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, purchase power contracts	6680-UR-110	2001
Wisconsin Public Service Commission	Wisconsin Electric fuel rate case, fuel costs, adequacy of planning, purchase power contracts	6630-UR-111	2001
Wisconsin Public Service Commission	Rulemaking regarding electric utility fuel and purchased power cost recovery	1-AC-197	2001
Wisconsin Public Service Commission	Nuclear spent fuel dry cask storage expansion at Point Beach	6630-CE-275	2000
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-112	2000

Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, prudence of plant maintenance practices, purchase power	6680-UR-110	2000
Wisconsin Public Service Commission	Rulemaking regarding environmental impact analysis and public input process	1-AC-185	1999
Michigan Public Service Commission	Over-recovery of revenues due to declining coal costs	U-11560	1999
Michigan Public Service Commission	Reasonableness of proposed settlement regarding recovery of nuclear plant replacement power costs through power cost recovery factor, suspension of factor	U-11181-R	1999
Michigan Public Service Commission	Fuel and purchase power surcharge, coal costs	U-11180-R	1998
Vermont Public Service Board	Prudence of Green Mountain Power purchase and management of Hydro-Quebec power	5983	1997
Michigan Public Service Commission	Analysis of coal costs, purchase practices, spot market	U-10971-R	1997
Michigan Public Service Commission	Suspension of the fuel and purchase power factor and planning in the transition to restructured utilities	U-11453	1997
Wisconsin Public Service Commission	IEC merger (of WPL/IES/IPC), need and environmental issues regarding proposed Mississippi River transmission crossings	6680-UM-100	1997
Pennsylvania Public Utility Commission	Restructuring, stranded cost, and securitization -- economic and environmental issues	R-00973877	1997
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of sales promotion	U-11181	1997
Wisconsin Public Service Commission	Primergy merger (of WEPCO/NSP), impact on state regulatory authority	6630-UM-100/4220-UM-101	1996
Michigan Public Service Commission	Gas cost recovery adjustments	U-10640-R	1996
Pennsylvania Public Utility Commission	Electric discounted rates, gas/electric competition	R-943280C0001	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of WEPCO/NSP merger	U-10966	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of energy efficiency	U-10971	1996
Minnesota House Committee on	Impact of cogeneration project on NSP	HF637	1996

Taxes	ratepayers		
Minnesota Senate Committee on Jobs, Energy and Community Development	Impact of cogeneration project on NSP ratepayers	SF1147	1996
Wisconsin Public Service Commission	Role of DSM in Advance Plan-7 in light of potential restructuring	05-EP-7	1995
City Public Service Board of San Antonio	Integrated resource planning process (1992 EPAct hearings)	NA	1994
Maryland Public Service Commission	1992 EPAct rules	8630	1994
Georgia Public Service Commission	Commercial and Industrial DSM programs for Savannah Electric	4135-U	1993
Public Utilities Commission of Ohio	Analysis of forecasts and long range plans for Ohio Power and Columbus Southern (case settled)	90-659-EL-FOR and 90-660-EL-FOR	1990
Georgia Public Service Commission	Integrated resource plan analyses for Georgia Power and Savannah Electric	4131-U and 4134-U	1992
New Orleans City Council	Least-cost planning rules	14629 MCS	1991
District of Columbia Public Service Commission	Potomac Electric least-cost plan analysis	834 Phase II	1990
Massachusetts Department of Public Utilities	Boston Gas plan integrated resource plans	90-55	1990
Massachusetts Department of Public Utilities	Boston Gas commercial and industrial DSM, cost recovery	90-320	1991
Hawaii Public Service Commission	Least-cost resource planning	6617	1991
Georgia Public Service Commission	Least-cost planning and facility certification rules	4047-U	1991
New Jersey Board of Public Utilities Commissioners	Transmission line certificate (case settled)	NA	1990
South Carolina Public Service Commission	Transmission line certificate	88-519-E	1988
Vermont Public Service Board	Least-cost planning	5270	1988
D.C. Public Service Commission	Least-cost planning	834	1987

Mendl also assisted in preparing testimony and testified in numerous cases as a senior staff witness at the Wisconsin Public Service Commission. Dates are approximate.

- Advance Plans 1 through 4 (Dockets 05-EP-1 through 05-EP-4 -- on various occasions between 1977 and 1988) before the Wisconsin Public Service Commission
  A wide variety of planning issues including forecasts, nuclear vs coal power, alternative energy, renewable energy, load management, transmission planning, demand-side management resources, principles and methods of integrated resource planning

- Rate Cases (various occasions between 1976 and 1988) including landmark time-of-use rate case (6630-ER-2) for Wisconsin Electric Power
  Environmental and consumer impacts of rate levels and alternative rate designs before the Wisconsin Public Service Commission

- Construction Cases before the Wisconsin Public Service Commission
  Pleasant Prairie Power Plant (1976-1978)
  Germantown Combustion Turbines (1976-1977)
  Weston 3 (1979)
  Edgewater 5 (1980)
  Apple River -- Crystal Cave Transmission Line (1980)
  Prairie Island -- Eau Claire Transmission Line (1981-1982)
  North Madison -- Huiskamp -- Sycamore Transmission Line (1982)
  Point Beach Nuclear Plant Steam Generator Replacement (1982)
  Wisconsin Natural Gas Pipeline (1986)
  Need for power, appropriateness of the utility proposals, and the comparative economics of alternatives, environmental impacts

- Other Appearances while employed at the Wisconsin Public Service Commission
  Planning investigation before the Connecticut Department of Public Utilities Control Authority (1975); uranium availability and resource alternatives
  Rulemaking proceedings before Wisconsin Legislative Committees (1975-1982); planning, siting, and environmental impact analysis rules
  Tyrone Nuclear Project Termination cost recovery hearing before the Federal Energy Regulatory Commission (1980)
  Acid Rain legislation before Wisconsin Legislative Committees (1984-1985)

Selected Clients

Mendl has served the following public sector clients since 1988.

Client	Nature of Service
Alaska Housing Finance Corporation	Analysis of applicability of EPAct standards to Alaska resource selection process.
American Public Power Association	Prepared whitepaper on distributed resources, "Distributed Resources: Options for Public Power" and presented it to APPA National Meeting and distributed resources workshops.
Arizona Corporation Commission	Analyze UNS Gas fuel procurement practices, provide testimony regarding prudence, and develop auditor training manual. Analyzed Sempra request to be allowed to compete for selected retail loads. Analyzed Sulphur Springs Valley Electric Coop purchase power practices.
California Low Income Governing Board	Analysis of options to deliver energy efficiency and assistance programs to low-income households in a restructured utility environment. Assist Board to develop low-income programs and policies under interim utility administration.
City of Chicago	Evaluate municipalization, especially regarding power availability and cost, transmission constraints, cogeneration potential.
Citizen's Utility Board of	Evaluate energy efficiency and load management programs in light

Wisconsin	of possible industry restructuring. Evaluate fuel rate cases and recommend revenue reductions in testimony for Alliant, Wisconsin Electric, Madison Gas & Electric and Wisconsin Public Service. Assess ATC formation and operation costs. Comment on and develop fuel rules, purchase power incentives. MISO collaborative
Center for Neighborhood Technologies	Analysis of value of avoiding generation, transmission and distribution through energy efficiency, load management and distributed generation.
Clean Wisconsin	Review Strategic Energy Assessments, provide comments to Wisconsin PSC
Conservation Law Foundation of New England	Collaboratives with Boston Edison, United Illuminating, Eastern Utilities Association, and Nantucket Electric regarding system planning approaches, avoided costs, resource screening. Collaborative with Green Mountain Power regarding Vermont Yankee end-of-life planning.
Dane County Energy Collaborative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet Dane County energy needs.
District of Columbia Energy Office	Analysis of DC Natural Gas' and PEPCo's integrated resource planning.
District of Columbia Public Service Commission	Testimony regarding least cost planning principles and rules.
Environmental Law and Policy Center	Analyzed potential impacts of proposed merger of Wisconsin Electric Power Company and Northern States Power Company on state regulatory authority in Wisconsin and Minnesota. Analyzed environmental impacts related to proposed merger of WPL and two Iowa utilities (IES and IPC), including the proposed transmission line crossings of Mississippi River and changes in air pollutant emissions. Analyzed electric and gas energy efficiency plans in Iowa, Illinois, Michigan and Ohio
Environmentalists/Penn. Energy Project	Analyzed PECO application to securitize stranded costs, especially on economic and environmental impacts that could result from authorizing overestimated stranded costs. Analyzed utility retail access pilot programs. Analyzed restructuring plans for PECO and PP&L.
Germantown Settlement, Philadelphia	Advise regarding business structure and market to aggregate load and/or provide energy efficiency and energy assistance services to low-income households.
Georgia Public Service Commission	Developed integrated resource planning and facility certification rules. Developed integrated resource plans and reviewed utility filings. Monitored utility DSM programs. Evaluated GP demand side plan for 2007 IRP. Analyzed DSM selection process in DSM Working Group setting on behalf of Commission Staff.
Hawaii Division of Consumer Advocacy	Developed integrated resource planning rules.
Illinois Citizens Utility Board	Analyzed Illinois electric supply auction, suggested modifications to better incorporate energy efficiency and demand response resources.

Iowa Department of Natural Resources	Developed and implemented workshops to train building operators and architects in energy efficiency and renewable energy resource opportunities.
Kentucky Public Service Commission	Analyzed need and alternatives for an EKPC transmission line and a prepared report. Presented testimony defending and explaining report. Analyzed need and alternatives for an AEP transmission line and a prepared report.
Lake Michigan Coalition	Analyzed nuclear spent fuel dry cask storage expansion proposal
Maryland Public Service Commission	Reviewed two utility long-range plans and suggested improvements.
Massachusetts Division of Energy Resources	Analysis of Boston Gas Co. integrated resource plans and residential energy efficiency programs. Analysis of Boston Gas's commercial and industrial energy efficiency programs.
Michigan Community Action Agency Association	Analysis of Michigan electric utility restructuring proposals and impacts on retail prices. Analysis of MichCon gas cost recovery case and factor. Analyses of Indiana-Michigan, Consumers Energy, Wisconsin Electric and Northern States Power-Wisconsin power supply cost recovery cases and factors, including analysis of coal and power purchase practices, demand-side management, and nuclear plant outage costs. Analysis of Northern States Power/Wisconsin Electric Power Co. proposed merger.
Missouri Public Service Commission	Developed rules for electric resource planning and gas resource planning. Evaluated three electric utility plans filed pursuant to rules.
National Association of Regulatory Utility Commissioners	Organized, prepared and presented at five workshops throughout the U.S. sponsored by NARUC/DOE.
Natural Resources Defense Council, Mid-Atlantic Energy Project Collaborative	Evaluated resource planning and selection processes used by PSE&G to prepare plan filings.
New Jersey Department of the Public Advocate	Analyzed a transmission line application.
City of New Orleans	Developed least cost planning rules, guided a public working group to develop demand-side programs.
Nevada Office of Attorney General, Bureau of Consumer Protection	Sierra Pacific Power and Nevada Power Energy Supply Plans, Base Tariff Energy Rates and Deferred Energy Adjustment Accounts - gas purchase practices and prudence; Southwest Gas and Westpac PGA prudence analysis, gas purchase practices
Nevada Public Utilities Commission, Regulatory Operations Staff	Southwest Gas PGA prudence analysis, gas purchase practices
Northeast States for Coordinated Air Use Management	Electric vehicle analysis.
Ohio Office of Consumer Council	Analyzed two utilities' long-range plans and energy efficiency resource options.

Ontario Energy Board	Evaluated need for natural gas integrated resource planning rules.
The Opportunity Council	Evaluated gas DSM programs to be considered by Cascade Natural Gas in Washington.
Pennsylvania Office of Consumer Advocate	Evaluated demand-side management programs for several electric utilities. Investigated causes of Winter Emergency of 1994. Analyzed electric "flexible rates" and gas/electric competition issues. Analyzed electric reliability concerns in a restructured and competitive market. Evaluated electric energy efficiency plans..
RENEW Wisconsin	Analyzed MG&E's green pricing tariff, compared costs of conventional resources to green resources to determine whether a green premium tariff was appropriate
Responsible Use of Rural and Agricultural Land (RURAL)	Evaluated air and licensing issues related to a proposed power plant. Evaluated Public Service Commission proposed environmental and siting rule changes. Analyzed rules governing environmental review and public comment process and provided testimony before PSCW.
South Carolina Office of Consumer Advocate	Analyzed a transmission line application.
Southeast Wisconsin Energy Initiative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet energy needs in southeastern Wisconsin.
Texas ROSE	Developed electric planning rules. Analyzed city of San Antonio resource plan.
U.S. Environmental Protection Agency	Developed handbook, "Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act", which focuses on how energy efficiency and renewables relate to acid rain compliance strategies.
U.S. Environmental Protection Agency and U.S. Department of Energy	Analyzed and compared utility supply- and demand-side resource selection for Clean Air Act compliance on the Pennsylvania-New Jersey-Maryland (PJM) interconnection.
Utah Committee on Consumer Services	Analyzed DSM cost recovery mechanism, avoided cost methods, cost effectiveness tests, assisted in settlement discussions and would have prepared testimony if issues not settled.
Vermont Natural Resources Council and Vermont Public Interest Research Group	Testimony regarding least cost planning principles and rules.
Vermont Public Service Board	Testimony regarding the prudence of Green Mountain Power's planning and management of the Hydro-Quebec power purchase.
Wisconsin Department of Administration	Analysis of new home characteristics built in northeastern Wisconsin, permit data, survey development and report
Wisconsin's Environmental Decade	Review of Draft Environmental Impact Statement of major 345 kV transmission line in northwestern Wisconsin, develop comments.

EXHIBIT JEM-2

REDACTED

EXHIBIT JEM-3

REDACTED

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
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JM – 3.28 Please describe the current organizational structure for implementation and oversight of Mohave's purchase power procurement method, including:

a) Identify who has responsibility for determining the volumes of purchase power to be procured;
b) Identify who has responsibility for securing bids;
c) Identify who has responsibility for evaluating offers;
d) Identify who has responsibility for deciding to accept or reject offers;
e) Identify the levels of management approval required to enter into a purchase power contract;
f) Identify who has responsibility for implementing a purchase power contract;
g) Identify who has responsibility for Mohave's price risk management activities; and
h) Identify who has ultimate authority for decisions regarding purchase power procurement.

Response:

a) Management in consultation with consultants and Western personnel are responsible for determining the volumes of purchase power to be procured with Management having the ultimate responsibility.

b) Under its agreement with Western, Western personnel have the responsibility for securing bids.

c) In consultation with the consultants for Mohave and Western, the Chief Executive Officer of Mohave has the responsibility for the final evaluation of offers.

d) The Chief Executive Officer of Mohave has the responsibility for deciding to accept or reject offers.

e) The Chief Executive Officer is the level at which approval is required to enter into a purchase power contract and this is accomplished after consultation and review of the dynamics of the proposed contract with Western and the consultants to Mohave.

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f) Implementation of a purchase power contract after approval and execution is the responsibility of Western under its agreement with Mohave.

g) Responsibility for Mohave price risk management activities is the responsibility of the Chief Executive Officer.

h) Ultimate authority for decisions regarding purchase power procurement is with the Chief Executive Officer who has the responsibility for reporting decisions to the Board.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

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Planned Power Procurement Approach and Organization

JM – 3.18 Does Mohave currently have a formal electric purchase power procurement strategy or purchase power supply plan? If yes, please provide a copy.

Response: The Power Supply Planning and Implementation documentation provided in the **Confidential** Attachment JM-3.8 reflects Mohave's effort to formalize the power supply planning process and implementation strategy. The guiding principles reflected in the document have not changed since Mohave became a PRM. However, implementation has changed and will continue to change to allow Mohave to deal with changing conditions. Given the dynamic conditions of the electric utility industry, the strategy and implementation continues to be discussed, reviewed and revised by the Board of Mohave in on-going consultation with Management.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
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JM – 3.19 Did Mohave have a formal electric purchase power procurement strategy or purchase power supply plan when it ceased being an all requirements customer of AEPCO? If yes, please provide a copy.

Response: No, not in the sense of formal written policy statement adopted by its Board of Directors. Mohave adopted a process of securing outside consultants and entities to assist it in power procurement. Mohave was able to benefit from the experience of Western Area Power Administration and their extensive experience in dealing in wholesale power markets. Western provided the framework for implementation of the power supply to serve load. This experience resulted in an informal process which was refined and expanded and eventually resulted in the Power Supply Planning and Implementation document provided in the **Confidential** Attachment JM-3.8.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

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JM – 3.20 Please provide a copy of any updates or amendments Mohave made to its formal electric purchase power procurement strategy or purchase power supply plan between July 25, 2001 and the present. Please identify when those changes occurred and the purpose of those changes.

Response: Mohave continues to follow the principals outlined in the Power Supply Planning and Procurement document in the **Confidential** Attachment JM-3.8 and to implement the processes and procedures which Mohave, Western, and the Consultants have found to be workable for Mohave.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
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JM – 3.27 Please describe when, how, and why Mohave's methods for communicating its written and/or informal procurement strategies to the procurement personnel responsible for the day-to-day electricity purchase decisions changed since July, 25, 2001.

Response: Changes are occurring on a continuous basis in response to changing conditions. Mohave's methods of communicating changes rely on direct communication with the individuals involved consistent with utilizing the Power Supply Planning and Implementation document previously identified and produced in the **Confidential** *Attachment JM-3.8*. Mohave does not have, and does not believe it necessary to have a formal process documenting the evolution up to its current procurement practices. A primary reason such documentation is unnecessary is that Mohave relies on Western and the procedures and policies that Western utilizes that are periodically reviewed with Mohave and provide the basic framework for the day-to-day operations.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

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JM – 3.29 Please describe when, how, and why Mohave's organizational structure for implementation and oversight of Mohave's purchase power procurement method described in the preceding question changed since July, 25, 2001.

Response: When Mohave became a PRM, Mohave put in place the basic relationship with Western, the consultants, and the Mohave staff. The basic areas of responsibility reflected in this organization structure have not changed significantly since 2001. After the first few years Mohave did place a staff person in Western's office. The objective was to have a Mohave employee become very familiar with Western's activities on behalf of Mohave and to help ensure proper coordination of the activities. Mohave's accounting staff also worked directly with Western and the Consultants in implementing accounting and reporting systems as required.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

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JM – 3.30 How does Mohave monitor the results of its purchase power procurement process, including how it determines whether situational deviations from its policies/procedures are needed?

Response: Mohave monitors with Western and its consultants the results of its purchase power procurement process, including determination of whether or not situational deviations from guidelines, processes, policies and procedures are needed on an incident by incident basis and on a weekly and monthly reporting basis. This monitoring process has existed since July 25, 2001. The process has become easier to implement as Western modified reporting formats to meet Mohave's needs and as Mohave staff became more familiar with Western's procedures.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
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JM – 3.31 Has Mohave changed its approach to monitoring the results of its purchase power procurement process since July 25, 2001? If so, please describe when, how, and why Mohave modified its approach?

Response: There has not been any significant change in approach. The underlying concepts involve Western, Staff, and Consultants working together. As in any such relationship, the activities become more efficient over time as everyone involved becomes more familiar with processes and reports.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

EXHIBIT JEM-6

REDACTED

EXHIBIT JEM-7

REDACTED

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
JUL 25 2001
DOCKETED BY

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC., FOR VARIOUS AUTHORIZATIONS ASSOCIATED WITH ITS RESTRUCTURING

DOCKET NO. E-01773A-00-0826

DECISION NO. 63868

ORDER

Open Meeting
July 24 and 25, 2001
Phoenix, Arizona

FINDINGS OF FACT

1. On October 11, 2000, Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative") filed an application for approval and confirmation of various transactions enabling the Cooperative's restructuring into three affiliated entities. The approvals and confirmations requested include:

A.) Approval of the transfer of AEPCO's transmission assets to Southwest Transmission Cooperative Inc. ("Southwest") and approval of the transfer of its cooperative service provider business to Sierra Southwest Cooperative Services, Inc. ("Sierra").

B.) Approval of AEPCO and Southwest to execute notes, mortgages and assumption and indemnity agreements associated with the restructuring.

C.) Approval of a partial requirements relationship between AEPCO and Mohave.

D.) Approval of the revised Class A member unbundled tariff and the forgiveness of the Purchased Power and Fuel Adjustment Clause.

E.) Confirmation that AEPCO has complied with the requirements of A.C.C. R14-2-1615 by this restructuring.

F.) Approval of waivers or, alternatively, approval of AEPCO's Code of Conduct.

G.) Confirmation that the financial commitment conditions of Decision No. 61932 pertaining to Sierra have been satisfied.

...

43. AEPCO will supply Mohave power and energy based on its historic demand and investment. However, Mohave will be free to procure its additional needs from other sources.

44. Because Mohave will only participate in the wholesale market for its incremental needs, the recent volatility in electric prices should present a minimal risk. In return, the partial requirement arrangement provides Mohave the opportunity to pursue advantageous pricing arrangements as the wholesale market matures and becomes less volatile and chaotic. Therefore, the Partial Requirements Capacity and Energy Agreement should be approved.

<u>Purchased Power and Fuel Adjustor Clause</u>

45. The fundamental rationale for a fuel adjustment clause is that fuel prices can change radically based on the overall energy market. During much of the time that AEPCO's restructuring was being planned, fuel prices were dropping. During the more recent past, there has been a dramatic reversal of that trend. It is likely that for at least the near future, energy prices will be unstable.

46. Purchased power and fuel adjustor clauses for Arizona utilities may be created and set during a rate case wherein a base cost of fuel and purchased power is determined and included in base rates. The base period cost of fuel and purchased power adopted in AEPCO's last rate case and used in the subsequent fuel adjustor filings is $0.01714 per kWh. AEPCO's most recent filing of its fuel and purchased power cost adjustment indicated that its current cost of fuel and purchased power is $0.026034.

47. AEPCO's application requested the Commission's approval to: (1) forgive the under-collected balance in its PPFAC bank as of the effective date of the restructuring and (2) to eliminate its PPFAC on an on-going basis.

48. As of December 31, 2000 AEPCO's PPFAC bank balance was undercollected by approximately $6.7 million. Between January 1 and March 31, 2001, AEPCO has accumulated an additional undercollected balance of $2.3 million.

49. Staff has not audited the cumulative expenses included in AEPCO's reported undercollected PPFAC balance in several years. Staff cannot confirm the amount undercollected without a complete audit of the historical PPFAC filings, accounting and related invoices.

...

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.15 Refer to Mohave's response to JM-4.14 part b. In-house labor expenses were not booked to Account 557 prior to 2008 and not recovered through the PPCA prior to 2010.

a) What prompted Mohave to book these in-house labor expenses to Account 557 in 2008? Were these new expenses first incurred in 2008? Or were these expenses incurred in prior years but booked to a different account prior to 2008? To which account were they previously booked?

b) Since these in-house labor expenses were not recovered through the PPCA, even though they had been booked to Account 557 beginning in 2008, why did Mohave propose to begin recovering them through the PPCA in 2010? What changed in 2009 or 2010 to cause Mohave to propose to recover in-house labor expenses through the PPCA?

Response:

a) Response to JM4-14 general narrative description and item (f) explain the objectives for booking in-house labor expenses to Account 557. Yes, these expenses were incurred in prior years, beginning in 2001 when Mohave became a Partial Requirements Member, and were booked to account 920.

b) The administration and accounting of Mohave's responsibilities as a Partial Requirements Member continues to be discussed, reviewed and revised by Mohave. The decision to recover in-house labor expenses through the PPCA was made as part of that on-going process.

Prepared by: Dorothy Pierce

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.16 Refer to Mohave's response to JM-4.14 part c. Consulting expenses were not booked to Account 557 prior to 2010, and some were booked to Account 555.11 in 2010, and none of these consulting expenses were recovered through the PPCA prior to 2010.

a) What prompted Mohave to book the consulting expenses to Accounts 557 and 555.11 in 2010? Were these new expenses first incurred in 2010? Or were these expenses incurred in prior years but booked to a different account prior to 2010? To which account were they booked?

b) Since these consulting expenses were not recovered through the PPCA, why did Mohave propose to begin recovering them through the PPCA in 2010? What changed to cause Mohave to propose to recover consulting expenses through the PPCA?

c) Please provide the same information for legal fees as in the previous sub-questions for consulting expenses.

Response:

a) Response to JM4-14 general narrative description and item (f) explain the objectives for consulting expenses to Account 557. Since becoming a Partial Requirements Member of AEPCO, Mohave has relied upon outside consultants to assist with power supply planning and administration. See Narrative provided in **Confidential** DR 3 JM-3.0 Narrative, Sections 2.0 and 3.0. Consulting expenses were incurred in prior years, beginning in 2001 when Mohave became a Partial Requirements Member, and were booked to account 923.

b) The administration and accounting of Mohave's responsibilities as a Partial Requirements Member continues to be discussed, reviewed and revised by Mohave. The decision to recover consulting expenses through the PPCA was made as part of that on-going process.

c) Legal fees were previously booked to Account 923.1. The responses to the sub-questions above are applicable to legal fees.

Prepared by: Dorothy Pierce

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
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JM – 4.14 **On page 10, lines 23-24, Mr. Stover includes "administrative and outside service fees associated with the power supply function" as components of wholesale power costs.**

a) Please identify and define the specific costs to which Mr. Stover is referring.

b) Do the administrative costs include any costs, or portions of the costs, of Mohave's internal staff, software, hardware, or facilities that are associated with the power supply function?

c) Please list each "administrative and outside service fees associated with the power supply function" that Mohave included in its purchase power adjustor mechanism, by month for each calendar year in the audit period, July 25, 2001 – December 31, 2010.

d) For each administrative and outside service fee listed above, please describe the amount of the cost, its purpose and to whom it was paid.

e) Please explain why Mohave believes these costs to be part of the wholesale power costs.

f) Please explain why Mohave believes these costs to be part of the costs of purchased power to be recovered through the purchased power adjustor mechanism.

Response: Prior to answering the specific questions, a general narrative description is in order.

Prior to 2001 Mohave was an all requirements member (ARM) of Arizona Electric Power Cooperative ("AEPCO"). AEPCO had the responsibility to:

- Forecast Mohave's future power supply requirements
- Identify the power supply options that could be a part of the power supply portfolio serving Mohave's retail load
- Determine the power supply options that best served the forecasted needs (owned resources, purchased power resources, market purchases)
- Acquire the needed resources
- Operate the resources
- Provide coordination services including scheduling and dispatching
- Arrange for transmission services for delivery of wholesale power supply to the ARMs
- Participate in proceedings in which AEPCO could be impacted by changes in rates charged for services

AEPCO performed these services using AEPCO staff and outside services. Those costs were passed through to Mohave as part of wholesale power

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supply and transmission rates. Mohave in turn reflected these costs in the retail rates charged to the member consumers.

Mohave is now a partial requirements member (PRM) of AEPCO. AEPCO's responsibility to the PRM is only to provide the allocated resources to the PRM consistent with the terms of the purchase power agreement. The PRM now has the responsibility to perform all of the services previously provided by AEPCO. The PRM must:

- Forecast future power supply requirements needed to serve the member retail load
- Determine the extent to which the AEPCO allocated capacity is sufficient to serve the load and identify capacity and energy deficiency
- Determine the power supply options available to make certain there are sufficient resources to serve the load
- Acquire the needed resources
- Arrange for the operation of resources
- Arrange for the scheduling and dispatching of the combined power supply portfolio so as to serve the retail load at the lowest cost.
- Arrange for transmission services to deliver capacity and energy to the system.
- Participate in any proceeding or hearings that could impact rates paid for wholesale power supply and transmission services.

Given the variety of activities involved, Mohave must have access to a variety of talents. In some cases the activities are routine, they are very predictable and the associated cost can be determined. Examples include the regular review of invoices and billing from third parties, the review of usage data for billing, daily scheduling and dispatching of resources. In other cases certain events are infrequent and the cost of performing the task is uncertain, such as participation in a wholesale or transmission rate case, negotiation of a power supply agreement, development of a new power supply resources. Starting in 2010, in-house or consulting expenses to be recovered through the PPCA are charged either to Account 555.11 or to Account 557 Other Expenses – Power Supply, and subject to review by the cooperative's auditors.

It is appropriate for Mohave to include all of the costs associated with the power supply function (cost from power supply providers, transmission providers, cost for outside services directly related to the power supply function, and staff costs directly associated with the power supply function) in defining wholesale power supply cost and that this value be used for the reconcilable power supply cost in the fuel and purchase power cost adjuster.

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As a result:

1. Mohave would have a complete accounting of all activities associated with the power supply function in a single account (sub accounts).
2. This would be consistent with how wholesale power supply costs were accounted for when AEPCO provided services to Mohave as an ARM.
3. Because the cost for the power supply function is "lumpy," i.e. there will be times when certain activities can be very intense, by including the cost as part of the PPCA Bank, there are two major benefits:
    a. Mohave can effectively spread the recovery of the irregular costs over longer period and effectively "smooth out" the cost.
    b. Mohave does not have to make a change in base rates in order to recover the cost.

Answers to specific questions:

a. An excel spreadsheet has been prepared and labeled Attachment JM-4.14 with a breakdown of the specific costs. The specific costs consist of in house labor and associated benefits and payroll taxes, a small amount of other expenses, and consultant and attorney fees. The types of activities involved include the regular review of invoices and billing from third parties, the review of usage data for billing, daily scheduling and dispatching of resources, participation in a wholesale or transmission rate case, negotiation of a power supply agreement and development of a new power supply resources.

b. Yes. See Attachment JM-4.14 to see the amount of in house labor and associated benefits, payroll taxes and the small amount of other expenses. There were no in house expenses booked to Account 557 prior to 2008. Starting in 2008, expenses were booked to Account 557 in every year. No in house expenses were recovered through the PPCA prior to 2010.

c. Attachment JM-4.14 shows the amount of fees by month by consultant. There were no consulting expenses booked to Account 557 prior to 2010. Some consulting expenses were booked in 2010 in Account 555.11. In the future, all consulting expenses to be recovered through the PPCA will be booked in Account 557. No consulting expenses were recovered through the PPCA prior to 2010.

d. Attachment JM-4.14 shows the amount of fees by month by consultant. The types of activities involved include the regular review of invoices and billing from third parties, the review of usage data for billing, daily scheduling and dispatching of resources, participation in a wholesale or

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transmission rate case, negotiation of a power supply agreement and development of a new power supply resources.

e. Mohave is now a partial requirements member (PRM) of AEPCO. AEPCO's responsibility to the PRM is only to provide the allocated resources to the PRM consistent with the terms of the purchase power agreement. The PRM now has the responsibility to perform all of the services previously provided by AEPCO. The PRM must:

   Forecast future power supply requirements needed to serve the member retail load.

   Determine the extent to which the AEPCO allocated capacity is sufficient to serve the load and identify capacity and energy deficiency.

   Determine the power supply options available to make certain there are sufficient resources to serve the load.

   Acquire the needed resources

   Arrange for the operation of resources

   Arrange for the scheduling and dispatching of the combined power supply portfolio so as to serve the retail load at the lowest cost.

   Arrange for transmission services to deliver capacity and energy to the system.

   Participate in any proceeding or hearings that could impact rates paid for wholesale power supply and transmission services.

f. It is appropriate for Mohave to include all of the costs associated with the power supply function (cost from power supply providers, transmission providers, cost for outside services directly related to the power supply function, and staff costs directly associated with the power supply function) in defining wholesale power supply cost and that this value be used for the reconcilable power supply cost in the fuel and purchase power cost adjuster.

   As a result:
   Mohave would have a complete accounting of all activities associated with the power supply function in a single account (sub accounts).

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This would be consistent with how wholesale power supply costs were accounted for when AEPCO provided services to Mohave as an ARM.

Because the cost for the power supply function is "lumpy," i.e., there will be times when certain activities can be very intense, by including the cost as part of the PPCA Bank, there are two major benefits:

a. Mohave can effectively spread the recovery of the irregular costs over longer period and effectively "smooth out" the cost.
b. Mohave does not have to make a change in base rates in order to recover the cost.

Prepared by: Carl N. Stover

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF MONTHLY COSTS CHARGED TO ACCOUNT 557

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Staff Payroll, Benefits and Payroll Taxes													
2008									4,758.22	4,666.02	10,671.19	2,435.65	22,531.08
2009	8,308.46	7,701.70	8,801.88	6,133.77	6,371.88	12,331.66	5,827.48	6,630.92	9,649.98	11,896.97	13,196.40	8,153.75	105,004.85
2010	12,488.77	23,478.46	9,995.90	4,599.71	6,684.08	6,741.25	10,325.78	10,888.34	8,093.80	9,170.78	8,258.52	9,110.89	119,836.28
Curtis Goodwin et al - Legal													
2008													-
2009													-
2010			58,033.02	13,589.50	50,057.06	38,429.50		57,065.06	35,160.79	34,257.40	56,419.15	17,182.34	360,193.82
Brian Cave - Legal													
2008													-
2009													-
2010									10,000.00				10,000.00
GMD & Associates - Legal													
2008													-
2009													-
2010				3,333.33	6,894.79		6,666.66				6,403.92	5,143.18	28,441.88
CH Guernsey - Consulting (Includes 555.11 in 2010)													
2008													-
2009													-
2010		172.75	7,770.00		17,973.72	12,721.64	16,241.23	8,105.93	4,623.60	9,116.35		(1,194.20)	75,531.02
Expenses (Staff Meeting and Travel)													
2008 *													-
2009 **												353.65	353.65
2010 ***								134.05			304.24	296.16	734.45
TOTAL													
2008 Expenses	-	-	-	-	-	-	-	-	4,758.22	4,666.02	10,671.19	2,435.65	22,531.08
Recovered from PPCA													
2009 Expenses	8,308.46	7,701.70	8,801.88	6,133.77	6,371.88	12,331.66	5,827.48	6,630.92	9,649.98	11,896.97	13,196.40	8,507.40	105,358.50
Recovered from PPCA													
2010 Expenses	12,488.77	23,651.21	75,798.92	21,522.54	81,609.65	57,892.39	33,233.67	76,193.38	57,878.19	52,544.53	71,385.83	30,538.37	594,737.45
Recovered from PPCA	12,488.77	23,651.21	75,798.92	21,522.54	81,609.65	57,892.39	33,233.67	76,193.38	57,878.19	52,544.53	71,385.83	30,538.37	594,737.45

** Expenses (Background Check)

*** Expenses (Staff Meeting and Travel)

[redacted]

Account 557.00

	2007	2008	2009	2010
Payroll Labor	$ -	$ 16,474.33	$ 82,284.50	$ 64,785.02
Total Benefits	$ -	$ 4,089.32	$ 16,132.90	$ 46,633.10
Worker's Comp	$ -	$ 458.88	$ 1,172.08	$ 1,935.36
Payroll Taxes	$ -	$ 1,508.55	$ 5,415.37	$ 6,482.80
Other*	$ -	$ -	$ 353.65	$ 451,886.39
Total	$ -	$ 22,531.08	$ 105,358.50	$ 571,722.67
Audited Trial Balance	$ -	$ 22,531.08	$ 105,358.50	$ 571,722.67
Account 555.10 (2010 Only)				$ 23,014.78
Total recovered through PPCA	$ -	$ -	$ -	$ 594,737.45
***Other Cost Descriptions:**				
Pre-Employment Background Check			$ 353.65	
Legal				$ 398,635.70
Consulting				$ 52,516.24
Meeting and Travel Expense				$ 734.45
Total	$ -	$ -	$ 353.65	$ 451,886.39

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.8 Please provide any reports, documentation or analyses produced in conjunction with any audits done internally, by independent auditors or regulatory agencies regarding Mohave power purchase function and activities since January 1, 2001.

Response: Since January 1, 2001 there are no reports, documentation or analysis produced in conjunction with any audits done by regulatory agencies concerning the Mohave power purchase function activities.

There have been annual audits by independent auditors. The Audit for the 2009 test year and 2008 were included with the Application as Schedule M. The 2010 audit was provided with Mohave's Supplemental Filing as Supplemental Schedule M. The audit for 2007 is included with Attachment JM-3.8.

Management regularly reports to the Board on power purchases during Board meetings, but these reports are not written. General Counsel has provided two written reports to the Board regarding Mohave power purchase functions and activities. Those are being provided as Confidential documents.

There is a June 18, 2009 Policy of Power Supply Planning and Implementation: Process and Procedures dated April 28, 2009 which is a document in draft form which evolved over time and was placed in written draft form in 2009. The Policy has been a matter of continuous discussion between Mohave Management and the Board of Directors, but the draft acts as general guidance for Mohave employees and its consultants. This is being provided as a Confidential document.

Reference Attachment JM-3.8 for:

a. Audit reports as referenced
b. General Counsel's written reports to Board **[CONFIDENTIAL]**
c. Power Supply Planning and Implementation documentation **[CONFIDENTIAL]**

Prepared by: Michael Curtis

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.8 Please refer to Mohave's response to question JM-3.48, specifically Attachment JM-3.48.

a) The monthly bank balance reports (Report FA-1) were not included for the years 2007, 2008 and 2009. Report FA-1 for August 2010 does not include the actual cost of purchased power. Please provide the missing information.

b) The invoices that accompany the January - July 2010 and September - December 2010 sum to be less than the actual cost of purchased power reported on line 3 of the FA-1 reports for the corresponding months. For each month in 2010, please indicate how the actual cost of purchased power reported on line 3 of the FA-1 reports was derived from the invoices provided. If there are invoices missing, please provide them.

c) For each year 2007 – 2010, please provide an executable copy of all spreadsheets that are used to generate the FA-1 reports.

Response:

a) Attachment JMM-3.48 Supplemental_Confidential (2007, 2008, 2009, and 2010) is spreadsheets containing calculations of costs for FA-1 reports and the monthly FA-1 reports submitted to ACC. The values in the files are audited numbers submitted to the ACC following the annual audit.
b) See Attachment JMM-3.48_Supplemental_Confidential 2010, worksheet "PPA_Adj" for monthly costs of purchased power reported on line 3 of the FA-1 reports.
c) See response to (a) above.

Prepared by: Dorothy Pierce

**MOHAVE ELECTRIC COOPERATIVE INCORPORATED'S
RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S NINTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
December 9, 2011**

Subject: All information responses should ONLY be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.

<u>Regarding 2008 Fuel Bank Report and Documentation</u>

JEM – 9.14 Please refer to spreadsheet Line 24, "Transmission- Firm Transm. Svc WAPA", the values for June through November are not supported by invoices or other documentation in Attachment JM-3.48 2009.Please provide the supporting documentation (e.g., invoices, receipts).

Response: See Attachment JEM-9.14 CONFIDENTIAL with invoices for June 2008 through December 2008.

Prepared by: Dorothy Pierce

EXHIBIT JEM-13

REDACTED

EXHIBIT JEM-14

REDACTED

EXHIBIT JEM-15

REDACTED

EXHIBIT JEM-16

REDACTED

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.6 Referring to the response to JM-3.42 in the preceding question, please clarify what is meant by the statement "a function of variable cost" in regards to Western's decision to schedule energy.

a) Is it AEPCO's variable production cost, including transmission cost, compared to market cost, including transmission (where the market cost may include some fixed costs the seller hopes to recover)?

b) Is it the variable cost as faced by Mohave, which would be the ACC approved energy rate for AEPCO resources and the market price of energy, both including transmission?

c) Please explain which variable costs Western considers in its dispatch of resources to serve Mohave's needs.

d) Is the same variable cost comparison used by Western to make scheduling decisions for Third Party Sales on Mohave's behalf? Please explain whether and how scheduling decisions by Western for Mohave's native load and Mohave's Third Party Sales would differ.

Response: a) If the reference to AEPCO variable production cost means cost incurred in an interval for a particular resource, this information is not available to the PRM. AEPCO does not provide real time variable production cost by interval.

b) The information available to the PRM in making a dispatch decision is the ACC approved effective energy rate (Energy Charge + PPFAC), the applicable AEPCO transmission rate, plus additional information available as described below.

c) Mohave does not have interval production cost data to make dispatch decisions. Mohave does have the ACC approved energy rates and the ACC approved transmission rates. In addition, Mohave has monthly fuel cost reports prepared by AEPCO and provided to the ACC. The fuel cost reports are typically available approximately 60 days after the end of the month. The reports show average cost data for the Base and Other resources for the reporting month. The reports also show other cost components that are part of the PPFAC and which can result in changes in the PPFAC. This information is used by Mohave to estimate trends in resource costs. Mohave will then determine the strike price used for making scheduling decisions. Currently, the primary focus is on the estimated Base Resource cost which is developed using the ACC approved Base energy charge, Base FFPAC charge, ACC approved transmission cost, losses, and information from the AEPCO fuel report.

d) Western utilizes the same information for making scheduling decisions for native load and third party sales with the exception of adjustments for transmission cost and losses, where applicable.

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

Prepared by: Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INCORPORATED'S
RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
DECEMBER 9, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JEM – 8.8 Spreadsheet Lines 32, 33 and 34 subtract the purchase power costs made to entities who [are] not subject to the purchase power adjustor. While this yields the purchased power costs subject to the PPA, it is unclear how the margins on non-PPA sales are flowed through to MEC's retail customers. Please explain in detail how the margins (revenues from non PPA sales minus the cost of power for non-PPA sales) offset the rates paid by MEC's retail ratepayers. Please provide your calculations.

Response: Mohave's third party sales are limited to either AES Sales or AES Energy Exchanges. The cost of purchased power (power supply + transmission) for third party sales is subtracted from the purchased power cost prior to calculating the PPA applied to Mohave members.

All margins end up in the members' patronage capital credit account and show as a liability on the Cooperative's balance sheet. Cash from positive margins associated with third party sales is available to fund construction or operations, thereby minimizes the necessity for funds through debt or rate increases. In the pending rate proceeding, Mohave has included $309,874 in margins from third party sales in its adjusted test year calculations and reduced the requested increase by that amount. See Schedules, F.4.1, F-4.0 p. 7, A-20, p.1 and A-1.0. If these margins are flowed back through the PPA, then the $2,980,757 requested increase would be increased to $3,290,631 (10.4% additional revenue).

Prepared by: Dorothy Pierce

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MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED TEST YEAR RESALE REVENUE AND POWER COST
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2009

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Excess Baseload Energy														
Available Baseload Energy	(MWh)	92,249	83,367	48,064	91,757	94,700	96,850	100,048	100,175	96,679	92,250	89,306	92,297	1,077,742
Baseload Energy Used for Load	(MWh)	45,103	41,110	42,568	45,771	68,394	67,029	86,366	80,488	71,787	48,953	42,726	51,154	691,449
Total Excess Baseload Energy	(MWh)	47,146	42,257	5,495	45,986	26,306	29,821	13,682	19,687	24,892	43,297	46,580	41,143	386,292
Total Excess % of Total Available		51%	51%	11%	50%	28%	31%	14%	20%	26%	47%	52%	45%	36%
5x8 Excess Baseload Energy	(MWh)	12,687	11,564	1,020	11,140	1,533	3,551	5	476	1,433	9,439	11,547	11,919	76,314
5x8 Excess % of Total Available		27%	27%	19%	24%	6%	12%	0%	2%	6%	22%	25%	29%	20%
Potential Products														
Possible 5x8 Excess product @ 99.5% Threshold	(MW)	40.0	45.0	-	10.0	-	-	-	-	-	12.5	50.0	40.0	
Associated Energy	(MWh)	8,000	8,280	-	2,080	-	-	-	-	-	2,500	9,600	8,640	39,100
% of 5x8 Excess Utilized in Product		63%	72%	0%	19%	0%	0%	0%	0%	0%	26%	83%	72%	51%
% of Total Excess Utilized in Product		17%	20%	0%	5%	0%	0%	0%	0%	0%	6%	21%	21%	10%
Forwards			Q1			Q2			Q3			Q4		
Forwards [Enter SuperPk Adder, either 1 or 2]		36.11	35.30	35.20	35.50	35.35	37.05	48.40	46.65	40.65	39.45	38.30	41.45	
Adder for Delivery to Mead		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Adder for SuperPeak Product	0.20	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	
Total		46.93	46.12	46.02	46.32	46.17	47.87	59.22	57.47	51.47	50.27	49.12	52.27	
Margin for Third Party Sales														
Energy Sales kWh		12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	476,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Revenue $		595,440.21	533,363.01	46,925.51	516,048.85	70,784.07	169,979.55	267.76	27,347.71	73,778.47	474,505.21	567,197.09	623,029.25	3,698,666.69
Cost of Power $		563,394.38	513,520.96	45,277.97	494,705.71	68,076.97	157,673.43	200.77	21,130.42	63,650.52	419,139.16	512,744.92	529,276.65	3,388,791.87
Margin $		32,045.83	19,842.05	1,647.54	21,343.14	2,707.10	12,306.12	66.99	6,217.29	10,127.95	55,366.05	54,452.17	93,752.60	$\boxed{309,874.82}$
Margin $/kWh		0.002526	0.001716	0.001616	0.001916	0.001766	0.003466	0.014817	0.013068	0.007066	0.005866	0.004716	0.007866	0.004061

Schedule F-4.1

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MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 RESALE (TPS) REVENUE AND POWER COST
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Excess Baseload Energy														
Available Baseload Energy	(MWh)	92,249	83,367	48,064	91,757	94,700	96,850	100,048	100,176	96,678	92,250	89,306	92,297	1,077,742
Baseload Energy Used for Load	(MWh)	45,103	41,110	42,569	45,771	68,394	67,029	86,366	80,488	71,787	48,953	42,726	51,154	691,449
Total Excess Baseload Energy	(MWh)	47,146	42,257	5,495	45,986	26,306	29,821	13,682	19,687	24,892	43,297	46,580	41,143	386,292
Total Excess % of Total Available		51%	51%	11%	50%	28%	31%	14%	20%	26%	47%	52%	45%	36%
5x8 Excess Baseload Energy	(MWh)	12,687	11,564	1,020	11,140	1,533	3,551	5	476	1,433	9,439	11,547	11,919	76,314
5x8 Excess % of Total Available		27%	27%	19%	24%	6%	12%	0%	2%	6%	22%	25%	29%	20%
Potential Products														
Possible 5x8 Excess product @ 99.5% Threshold	(MW)	40.0	45.0	-	10.0	-	-	-	-	-	12.5	50.0	40.0	
Associated Energy	(MWh)	8,000	8,280	-	2,060	-	-	-	-	-	2,500	9,600	8,840	39,100
% of 5x8 Excess Utilized in Product		63%	72%	0%	19%	0%	0%	0%	0%	0%	26%	83%	72%	51%
% of Total Excess Utilized in Product		17%	20%	0%	5%	0%	0%	0%	0%	0%	6%	21%	21%	10%
Forwards			Q1			Q2			Q3			Q4		
Forwards [Enter SuperPk Adder, either 1 or 2]		36.11	35.30	35.20	35.50	35.35	37.05	48.40	46.65	40.65	39.45	38.30	41.45	
Adder for Delivery to Mead		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Adder for SuperPeak Product	0.20	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	
Total		46.93	46.12	46.02	46.32	46.17	47.87	59.22	57.47	51.47	50.27	49.12	52.27	
Margin for Third Party Sales														
Energy Sales kWh		12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	475,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Revenue $		595,440.21	533,363.01	46,925.51	516,048.85	70,784.07	169,979.55	267.76	27,347.71	73,778.47	474,505.21	567,197.09	623,029.25	3,698,866.69
Cost of Power $		535,827.74	488,394.61	43,062.54	470,499.99	64,746.00	149,958.54	190.95	20,096.52	60,536.13	398,630.87	487,656.54	503,379.38	3,222,979.80
Margin $		59,612.47	44,968.40	3,862.97	45,548.86	6,038.07	20,021.01	76.81	7,251.19	13,242.34	75,874.34	79,540.55	119,649.87	$\boxed{475,885.89}$
Margin $/kWh		0.004699	0.003889	0.003789	0.004089	0.003939	0.005639	0.016990	0.015239	0.009239	0.008039	0.006889	0.010039	0.006233

EXHIBIT JEM-19

REDACTED

EXHIBIT JEM-20

REDACTED

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MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED PPCA BASE COST - 2010 DATA

	Adjusted 2010	Proposed 2010	Difference
Total kWh Sales	655,743,735	655,743,735	0
Less Lighting kWh Sales	1,100,103		(1,100,103)
Jurisdictional kWh Sales	654,643,632	655,743,735	1,100,103
Purchased Power	58,579,697	58,579,697	0
Power Cost per kWh Sold	0.089483	0.089333	(0.000150)
Authorized Base Cost	0.065798	0.091183	0.025385
Average PPCA Factor	0.023685	(0.001850)	(0.025535)

Adjusted 2010 Power Cost on Supplemental Schedule F-7.0
Adjusted 2010 kWh Sales on Supplemental Schedule F-2.0
Note: PPCA to be charged on lighting under new rates

EXHIBIT JEM-22

REDACTED

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF) MOHAVE ELECTRIC COOPERATIVE, INC. FOR) A DETERMINATION OF THE FAIR VALUE OF) ITS PROPERTY FOR RATE MAKING PRUPOSES,) TO FIX A JUST AND REASONABLE RETURN) AND TO APPROVE RATES DESIGNED TO) DEVELOP SUCH A RETURN)	DOCKET NO. E-01750A-11-0136

SURREBUTTAL

TESTIMONY

OF

JERRY MENDL

ON BEHALF OF COMMISSION STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

EXHIBIT

S-7

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

This surrebuttal testimony responds to the rebuttal testimony of MEC witnesses Carlson, Stover and Searcy. It also responds to additional information that MEC has provided since the filing of Staff direct testimony to document the purchased power costs in incurred from August 2001 through December 2006.

As a result of this additional documentation, Staff was able to refine and reduce the amounts of the adjustments Staff recommended to the purchased power bank balance. Ratepayers would still receive credits, but less credits than it would have been before MEC supplied additional documentation supporting its purchased power costs for 2001-2006.

Nothing in MEC's rebuttal testimony or in the information MEC provided resulted in any changes to Staff's recommendations regarding the purchased power base cost which was based on a 2010 test year.

Following is a summary of the recommendations Staff made in its direct testimony as supplemented or modified in this surrebuttal testimony. Staff recommends that the Commission:

1. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

2. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable. In addition, direct MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on MEC resource planners.

3. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

4. Reaffirm that for purposes of the purchased power adjustor, purchased power shall include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

5. Adopt Staff's specification of cost components which may be included in the fuel and purchased power cost adjustor. The specified cost components shall be limited to RUS Accounts 555, 565, and 447 for purchased power and 501 and 547 if MEC purchases fuel for power generation in the future. These are the same components specified by the Commission in 2005 for AEPCO.

6. Remove $594,737 from the 2010 test year base cost of power those costs ineligible for recovery through the purchased power adjustor that MEC has included as purchased power costs in 2010, namely in-house labor costs, consulting costs, lobbying costs and legal costs associated with planning and procurement of purchased

power. Reallocate $562,035 of those costs to revenue requirements for the general rates.

7. Reduce MEC's purchased power bank balance (credit to ratepayers) by $594,737 to adjust for the inclusion of these ineligible costs as soon as practical after the Commission issues its order in this docket.

8 Reduce MEC's purchased power bank balance (credit to ratepayers) by $91,537 to adjust for MEC's errors and omissions in calculating the purchased power cost and bank balance between August 2001 and December 2010, inclusive.

9. Determine that the actual eligible purchased power costs were adequately documented from August 2001 through December 2010.

10. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible costs and errors and omissions, are prudent and reasonable for August 2001 through December 2010.

11. Require MEC to file a rate case with purchased power prudence review no later than September 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapse between this rate case and the next rate case to ensure the purchased power cost data and supporting information remain fresh. The prudence review will cover the period beginning January 2011and ending in December of the test year. MEC may file sooner if necessary, with a test year ending no more than 8 months prior to the filing date.

12. Require MEC to adjust the bank balance in the next prudence review to remove in-house labor costs, consulting costs, lobbying costs and legal costs associated with planning and procurement of purchased power that MEC included in its purchased power adjustor in 2011 and 2012. Although identified as ineligible costs in this rate case (prudence review through 2010), the costs will actually have occurred in the next prudence review period and the adjustments shall be made in that review.

13. Require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided; Staff shall recommend that any undocumented and/or unverified costs be denied including interest or that the purchased power adjustor be eliminated.

14. Require MEC and Staff to meet within two months of this order to discuss options for streamlining the rate case process. Also identify issues and information required for the next case, leaving the flexibility to modify the issues as the case approaches.

15. Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

16. Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

17. Acknowledge that MEC's selection and management of Western Area Power Administration ("Western") to provide critical services are prudent and reasonable.

18. Require MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period.

19. Adopt a base purchased power cost of $0.087701 per kWh.

INTRODUCTION

Q. Are you the same Jerry E. Mendl who filed direct testimony in this docket on January 12, 2012?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond on behalf of Utilities Division Staff ("Staff") to the rebuttal testimony submitted by Mr. Carlson, Mr. Stover and Mr. Searcy. I am responding to the following subjects raised in the rebuttal testimony, many of which were addressed by more than one of Mohave Electric Cooperative's ("MECs") witnesses:

1. Adjustment of purchased power bank balance for undocumented 2008 power costs;
2. Adjustment of purchased power bank balance for undocumented 2001-2006 power costs;
3. Adjustment of purchased power bank balance and base rate for ineligible expenses;
4. Application of margins on third party power sales to reduce purchase power costs charged under Purchase Power Cost Adjustor ("PPCA");
5. Reconsideration of limits on spot market purchases;
6. Future case filing schedules and content; and
7. Other issues.

SECTION 1: UNDOCUMENTED 2008 POWER COSTS

Q. Are you still recommending that the Arizona Corporation Commission ("Commission") disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008 and credit the ratepayers by reducing the bank balance by that amount?

A. No.

Q. Why not?

A. After Staff filed testimony on January 12, MEC provided additional information. MEC provided documentation adequately supporting those claimed expenses on January 20, 2012, in its Supplemental Response to JEM-9.14. The issue and adjustment are moot as a result.

RECOMMENDATIONS

Q. What is your recommendation?

A. I recommend that the Commission determine that the actual eligible purchased power costs were adequately documented in 2007, 2008, 2009 and 2010.

SECTION 2: UNDOCUMENTED 2001-2006 POWER COSTS

Q. Are you still recommending that the Commission impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and credit ratepayers by reducing the bank balance by that amount?

A. No.

Q. Why not?

A. MEC has since provided most of the missing documentation.

In a February 17, 2012 meeting with Staff, MEC agreed to provide the missing documentation for 2001 through 2006. The missing documentation involved both the expenses that flow into the purchased power adjustor and the credits that offset some of those costs in the adjustor. Based on MEC's initial responses to JEM-13.1 and JEM-13.2, Staff was able to identify claimed expenses of $47,603,244.39 for which Staff had no documentation in the August 2001 through December 2006 period. In addition, Staff identified $9,556,853.76 of credits for which Staff had no documentation in that period.

Through several supplemental responses to JEM-13.1, MEC was able to provide documentation for additional claimed costs and credits. As of March 7, 2012, MEC had provided documentation adequately supporting all but $134,933.00 of claimed expenses for the August 2001 through December 2006 period, and all but $769,026.98 of credits applied to the calculation of the purchased power adjustor during that period. The remaining undocumented expenses consist of $134,933.00 of power MEC purchased from Aggregated Energy Services ("AES") in July 2002. Undocumented credits in the amount of $768,708.00 are the result of power MEC sold to AES in August – December 2002. MEC indicates that no documentation of the AES expenses and credits is available from 2002 because, at that time, AES members did not exchange invoices. The remaining undocumented credit is for $318.96 from Citizens Utilities in April 2004. MEC believes it was misfiled but cannot justify searching further for it. See Surrebuttal Exhibit JEM-6.

On March 12, 2012, MEC provided secondary documentation of the volumes of power purchased from and sold to AES in July through December 2002. These were derived from the amount of energy dispatched monthly from resources available to MEC and the monthly amount sold to serve native load, multiplied by the average rates then in effect. These derived values, while not matching the FA-1 reports precisely, provide sufficient documentation to support the recorded costs and credits. The remaining amounts are negligible.

Based on the documentation for most costs and credits MEC provided since Staff filed its direct testimony, Staff is no longer recommending the $1.946 million prudence adjustment. Because the remaining undocumented amounts are negligible, Staff is recommending no prudence adjustment for undocumented costs and credits.

Staff believes that MEC has made a good faith effort, though belatedly, to provide this documentation. However, Staff believes that the documentation supporting costs and credits used in the calculation of the purchased power adjustor and purchased power bank balance should be maintained and accurate. It should not have taken this much time and effort to verify calculations MEC must have performed to prepare its FA-1 reports. Staff believes this problem will be mitigated or eliminated in the future by its recommendation that no more than five years elapse between MEC's rate cases.

Q. Does Staff's elimination of the $1.946 million prudence adjustment render the arguments made in rebuttal testimony of MEC's witnesses moot?

A. Yes, although one deserves some attention. MEC witnesses Carlson and Stover contest my statement regarding the missing documentation of costs and credits for 2001-2006, specifically that "it is likely that the requisite information is no longer available." Mendl Public Direct, page 26, lines 13-14. Both witnesses Carlson and Stover argue that my claim that the information is likely to not be available is unsubstantiated and led to the wrongful application of the prudence adjustment. They in fact suggested that Staff was at fault for not having compelled them to provide the information after they refused to provide it.

My observation that the information was quite likely not available was based on MEC's own statement in its September 8, 2011 letter from Mr. Sullivan objecting to Staff Data Request Set 3 requesting information back to 2001. Mr. Sullivan stated:

> Importantly, not only do these requests seek a large amount of detailed information involving periods well outside of the test year ending December 31, 2009 that would be extremely burdensome *if not impossible to gather*, the Commission's Decision No. 72055, dated January 6, 2011 renders the bulk of the information of limited or no value in accessing Mohave's current and future power purchasing practices. (Emphasis added)

Since MEC understood that Staff was performing a prudence review, and since it is in the Company's self interest to provide all documentation supporting the costs subject to the performance review, I concluded that MEC's objection to providing the requested information was most likely because significant portions of it were "impossible to gather." Given the risk of disallowance of expenses that MEC did not document, I reasonably believed MEC would not withhold information that it possessed.

My belief that MEC would not withhold documentation of costs was ultimately proved wrong, and in the time since Staff filed testimony proposing the prudence adjustment, MEC was able to provide much of the needed documentation. However, MEC also proved my statement that it is likely that the "requisite information is no longer available" to be correct in that MEC could only produce derived approximate secondary documentation for over $900,000 of costs and credits.

Q. Does the documentation that MEC has now provided address the infrastructure, organization and policy/practices that MEC had in place between 2001 and 2010?

A. No. The information provided was documentation of the costs. It did not address whether MEC had an appropriate power procurement process, including MEC's organization and power planning and procurement approaches, prior to 2010. Staff's recommendation that the Commission determine that it is inconclusive whether MEC's policies of power supply planning and implementation prior to 2010 are reasonable and appropriate.

Q. Does the fact that MEC has now provided the documentation needed to support its costs for 2001-2006 mean that those costs are prudent?

A. No. It simply means that the costs were verified to exist. It does not mean that they are prudent or that they should be recovered through the purchased power adjustor mechanism.

Q. What additional analyses did you perform for the 2001-2006 purchased power costs?

A. I examined the data for ineligible costs. I also compared the purchase power prices to the market prices and checked for errors or omissions in the calculation of the purchased power costs and bank.

INELIGIBLE COSTS

Q. Did you find any ineligible costs that MEC included in the August 2001 through December 2006 purchase power cost adjustor and bank mechanism?

A. No. All of the costs in that time period appear to be direct costs of power purchases or sales) and their associated transmission. MEC did not attempt to incorporate legal and consulting costs, lobbying costs, or in-house staffing costs as it did in 2010.

COMPARISON TO MARKET POWER PRICES

Q. How did MEC's average purchase power costs compare to market prices in the August 2001-December 2006 period?

A. MEC's average purchased power costs excluding transmission compared favorably with market prices. Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 1, compares the MEC average cost excluding transmission to the monthly Mead market price. The shaded band represents the range between monthly off-peak and on-peak prices at Mead. MEC's average monthly purchased power cost could be expected to fall within or below the band. Generally, it does.

Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 1, is an update of Exhibit JEM-15 CONFIDENTIAL, page 1. Both cover the entire January 2001 through December 2010 period. MEC's average costs differ slightly in Surrebuttal Exhibit JEM-1 CONFIDENTIAL because these are based on the final actual fuel costs provided by MEC for 2001-2006 in response to JEM-13.1 and JEM-13.2. MEC's average costs as displayed in Exhibit JEM-15 CONFIDENTIAL, page 1, were based on unverified Staff information for 2001-2006.

Q. How did MEC's costs for block power purchases compare to market prices in the August 2001-December 2006 period?

A. Three of the four block purchase prices were in line with market prices. The fourth, which was in effect from 2001 through early 2003, was between two and three times the Mead market prices and MEC's average price. Please refer to Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 2.

Q. Why were the prices of the fourth block power purchase so high when compared to the market prices?

A. As I previously discussed in my direct testimony, there could be several reasons. First, the contract was likely negotiated at a time that the market prices were much higher. Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 1 shows that market prices in the first quarter of 2001 were above the price of the expensive block purchase which was in effect by August 2001. If market prices had not tumbled, the block power purchase would have appeared quite economic.

Second, the contract is a demand and energy type contract. The demand charges represent roughly half of the monthly cost, except in the final months of the contract. The demand charges then were about 80% of the monthly cost. The energy charge was slightly above the Mead market price, meaning that any discretionary take of power under this contract would be small. This block purchase ended up taking on the character of a capacity supply rather than an energy supply. Dividing a fixed demand cost by fewer kWh increases the average rate for the block purchase. Since the average rate of the block purchase is presented in Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 2, it is not surprising that it is much higher, especially for the months late in the contract. If Mead market prices had not fallen so much after the contract was negotiated, it is possible that more energy would have been taken under the contract, substantially reducing its average price per kWh.

Q. Did MEC act imprudently when purchasing this block power contract?

A. No. Due to these factors, although the average cost of that block purchase is substantially above market prices, I cannot conclude that MEC acted imprudently in obtaining that power given the nature of the market prices while it was being negotiated and subsequent falling of market prices.

In any event, this contract supplied less than 0.1 percent of the energy required by MEC. It would have little effect on the overall cost or rates.

ERRORS IN THE CALCULATION OF THE PURCHASE POWER COST

Q. Did you identify any errors in the calculation of the purchased power costs included in the purchased power adjustor and bank?

A. Yes. The errors and omission resulted in the over-collection of purchased power costs from MEC's ratepayers through the purchased power adjustor mechanism in the amount of $91,537.43.

Q. Please describe the error that you found.

A. The error is that MEC overstated the impact of the load control adjustment when calculating the amount of the purchased power cost that should be allocated to its ratepayers.

MEC's calculation of actual purchased power costs consists of adding all of its purchased power costs, and then subtracting the costs of supplying special contracts and third party sales to arrive at the net cost of purchased power for those customers subject to the purchased power adjustor rate. MEC calculates the cost of supplying special contracts and third party sales by applying the applicable rates for power from AEPCO to the volumes it sells to special contracts and third parties. In most months, the cost of power to supply a special contract is simply the volume multiplied by AEPCO's Commission-approved flat energy rate. The cost to supply the special contract is subtracted from the overall cost, leaving the rest to be recovered from ratepayers. The higher the cost to serve the special contract, the less of the total cost is borne by other ratepayers.

One special contract contains a load control provision. When that provision is exercised, it reduces the cost of serving the special contract load because AEPCO provides a credit on its billing to MEC. Thus MEC's overall actual costs decrease. MEC made an error in its calculation of the load control billing credit, overstating the actual credit. By overstating the actual load control credit and applying that calculated load control credit to the cost of serving the special contract, MEC shifted costs to its ratepayers subject to the purchase power adjustor.

Q. How were the costs shifted to MEC's ratepayers?

A. The shift occurred because MEC's ratepayers pay the remainder of the actual purchased power costs after having subtracted the cost of serving the special contract's loads. By overstating the amount of load control credit generated by the special contract customer, MEC understates the actual cost of serving the special contract customer. Because customers subject to the purchased power adjustor pay the remainder of the actual total purchased power cost, understating the cost of serving the special contract will overstate the cost of serving everyone else.

Q. How did you calculate the costs of this error?

A. MEC's spreadsheets show the calculation of the load control credit which then goes on to reduce the apparent cost of serving the special contract. The load control adjustment was applied in 11 months during the time period August 2001 through December 2010. I looked up the AEPCO billing to MEC for each of those eleven months to determine the actual load control credit received by MEC. The difference over all eleven months was

$90,166.38 over-billed to the ratepayers subject to the purchase power cost adjustor. Please refer to Surrebuttal Exhibit JEM-2 CONFIDENTIAL.

Q. Where did the extra money collected from MEC's ratepayers go?

A. It should have ended up in the members' patronage capital credit account. By understating the actual cost of serving the special contract, MEC would overstate the apparent margin on its special contract sales. The margins should flow to the members' patronage capital credit account. The higher calculated margins would be generated by increased costs borne by all ratepayers subject to higher rates under purchased power adjustor mechanism.

This is another reason that margins on sales to entities not subject to the purchased power cost adjustor mechanism should offset the purchased power costs, as I recommended in my direct testimony.

Q. Did MEC make any other errors in the calculation of the purchased power costs included in the purchased power adjustor and bank?

A. Yes. In the documentation supplied by MEC in response to JEM-13.1, MEC used $5,958.58 and $4,943.78 of power for self use in July and September 2003, respectively. The corresponding values used in the spreadsheets to calculate the actual purchased power costs were $4,584.48 and $4,949.78. The cost of power for self use is not included in the actual costs included in the purchased power adjustor and bank. It is subtracted from the total cost of power purchased, like the power purchased to serve special contracts. Thus understating the self use increases the cost to MEC's ratepayers subject to the PPCA.

MEC's documentation shows that MEC understated the cost of self-use power in July 2003 by $1,374.10 and overstated the cost of self-use power in September 2003 by $6.00. The net impact of the self-use errors is an adjustment to credit the purchased power bank by $1,368.10.

Q. Are you recommending any other adjustment to the costs in the 2001-2006 time frame?

A. Yes. In January 2005, AEPCO corrected an error on its December 2004 bill to MEC. The correction was a credit plus the interest. MEC recorded only the correction in its calculation of the actual cost and bank balance. It should have also included the interest. Correcting that omission would reduce ratepayer purchased power costs by $2.95. Although this amount is insignificant, the concept is not.

Q. Please summarize your recommended adjustments for errors and omissions?

A. The Commission should adjust the purchased power bank balance to credit MEC's customers in the following amounts:

Load Control Error	$90,166.38
Self-use Error	$1,368.10
Interest Omission	$2.95
Total Errors and Omission Adjustment	$91,537.43

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission:

1. Determine that it remains inconclusive whether MEC's policies of power supply planning and implementation as they existed from August 2001 through December 2009 were appropriate and reasonable.
2. Determine that MEC's actual purchased power costs are now adequately documented beginning in August 2001 through 2006.
3. Reduce MEC's purchased power bank balance by $91,537.43 to adjust for calculation errors and omissions.
4. Determine that MEC's remaining actual purchased power costs for the period August 2001 through 2006 are prudent and reasonable.

SECTION 3: INELIGIBLE EXPENSES

Q. In your direct public testimony, page 17 line 12, you indicated that Staff was not able to reach a conclusion whether MEC included ineligible costs in its purchased power adjustor during the August 2001 through December 2006 time frame. In light of the documentation provided by MEC since February 28, 2012, have you determined whether MEC included ineligible costs in 2001-2006?

A. Yes. Staff has now concluded that MEC did not include any ineligible expenses among the costs used to calculate the purchased power adjustor and bank balance for 2001-2006.

Q. Mr. Stover argues (rebuttal, page 17) that the ineligible costs should be included because they meet two criteria that you set forth in your direct testimony. Is this a compelling argument?

A. No. My testimony stated "As a ratemaking principle, fuel and purchased power clauses are reserved for volatile price changes that are outside the control of the regulated utility." Mr. Stover transformed that straightforward statement into two criteria, namely that any costs within the control of the utility should be recovered through general rates and any volatile costs can be include in an adjustor. My statement was clearly predicated on fuel and purchased power costs as an overriding criterion. In-house staff costs, legal fees and consulting services are not fuel and purchased power costs, even if they might be related to purchased power. MEC is requesting the Commission to step onto a slippery slope. If in-house staff costs associated with managing and recording power purchases are part of the purchased power adjustor, what would differentiate them from the in-house staff needed to evaluate system alternatives (to conduct long range planning activities)? Or from the secretarial/administrative staff used to prepare letters, invoices, and make payments? Or from the resources needed to prepare bills to retail customers to recover the costs of the purchased power? The overarching requirement that a cost be included in the purchased power adjustor is that it is for purchased power and associated transmission. The costs that I identified as ineligible do not meet that overarching criterion – they are not purchased power costs.

Q. Has the Commission previously addressed what costs could be included in a fuel and purchased power cost adjustor for a cooperative?

A. Yes. The Commission addressed that issue in an AEPCO application for a rate increase in 2004. By Decision No. 68071, the Commission adopted Staff's specification of cost components that could be included in a fuel and purchased power cost adjustor. AEPCO concurred with Staff's specification. MEC was a party to the case.

Q. What cost components did Staff specify would be included in the adjustor in the AEPCO rate case.

A. Staff specified that:

> The cost components would be the costs recorded in RUS Accounts 501 (fuel cost for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 547 (fuel costs for other power generation), 555 (purchased power costs, both demand and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included. Power supply costs directly assignable to special contract customers would not be included in the calculation. Non-Class A sales for resale (RUS Account 447), less revenue for legal expenses, would be credited against the cost components. Direct Testimony of Barbara Keene, Docket No.E-01773A-04-0528, page 3).

Excerpts from Ms. Keene's testimony are attached as Surrebuttal Exhibit JEM-3.

Q. Is the same specification of cost components appropriate and applicable for MEC?

A. Yes. At this time, MEC would use only Accounts 555 and 565 and 447 as appropriate. I have attached the RUS definition of those accounts in Surrebuttal Exhibit JEM-4.

MEC currently owns no generation and thus would have nothing to include for fuel costs in Accounts 501 and 547. MEC does evaluate the option of owning generation as part of its planning process. It is possible that MEC will own generation capacity in the future, at which point all the cost components would be utilized.

The Commission should direct MEC to base its purchased power cost adjustor (and the fuel and purchase power cost adjustor if that becomes applicable to MEC in the future) on the same cost components the Commission previously specified for AEPCO.

Q. Mr. Carlson states his understanding "that had these costs not been collected through our PPCA, Mohave's financial performance would have been adversely affected." (Rebuttal, page 13, line2) What is your perspective on this point?

A. Mr. Carlson effectively admitted to developing a new revenue stream which raises rates without Commission approval. Here is why.

Until 2010, MEC indeed had not collected those costs through their PPCA. Prior to 2010, these ineligible costs were being incurred by MEC but recovered through the general rates. In 2010, apparently as the Company's financial performance was becoming challenged, MEC segregated out these ineligible costs and included them in the PPCA – an action Mr. Carlson states was needed to avoid adversely impacting financial performance.

MEC created a new revenue stream to collect the ineligible costs through the PPCA mechanism, but did not correspondingly reduce the revenue stream from general rates that had provided recovery for the ineligible costs. When MEC talks about recovering these ineligible costs through the PPCA, what it is really doing is doubling up on its recovery, since from August 2001 through December 2009 (at least) these costs were being recovered exclusively through the general rates.

If MEC's point was to simply reclassify the ineligible expenses to roll them into the PPCA, it would have removed them from the general rate classification when MEC moved them to the PPCA. In fact, MEC increased the revenue stream by unbundling legal, consulting and in-house staff costs and rebundling some of them with purchased power and recovering costs in both places.

Q. Mr. Stover testifies that if the Staff proposal regarding ineligible costs is adopted, that the ineligible costs MEC recovered through the PPCA in 2010, 2011 and until the effective date of the order in 2012 "should not be included in the prudence adjustment because this would result in refund to the consumers of costs that the Commission has determined to be recoverable." (Rebuttal page 18, line 31) Do you agree?

A. No. I would agree if MEC had reduced its general rates when it segregated out the ineligible costs for inclusion in the PPCA. But it did not. Thus while the Commission would determine that all of the ineligible costs, except the lobbying costs, would be recoverable, they would have been recovered through the base rates. Thus the ineligible costs included in the PPCA in 2010 should be disallowed in the current rate case by adjusting the purchased power bank. Including lobbying costs, the entire $594,737 should be removed from the purchased power bank effective right after the order is issued.

The 2011 and partial 2012 ineligible costs will also have been collected in the general rates as well as through the PPCA. Staff's recommendation in my direct testimony was that the Commission "direct MEC to adjust that bank balance for any ineligible costs that may have been recovered through the purchased power adjustor after December 31, 2010." (Mendl Public Direct testimony, page 46. line 22) The amount of the adjustment will not be known until after MEC ceases its current practice of including ineligible costs in the PPCA, which will be as of the effective date of the order in the current case. Staff did not specify a date by which that adjustment would be made; however, the reasonableness and prudence of MEC's purchased power costs would normally be part of the prudence review in the next rate case. As a result, the purchased power bank should be adjusted to disallow whatever ineligible costs MEC has recorded in its PPCA during the next prudence review. If the Commission adopts Staff's recommendation, that prudence adjustment would be made in the case filed in 2016. This will spread the adjustment over two dates five years apart, thereby mitigating the financial impact on MEC.

Finally, the 2010 test year serves as the base *for forward looking rates*. As such, the entire $594,737 of ineligible expenses from 2010 should be removed from the PPCA test year. The ineligible expenses, except for lobbying, would be included in the general rates, set in such a way to recover all costs other than purchased power while providing adequate financial coverage.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission:

1. Disallow $594,737 of ineligible expenses from 2010 from the purchased power bank balance effective as soon as practical after the Commission issues the order in the current docket.
2. Disallow the ineligible expenses from 2011 and 2012 collected through the PPCA as soon as practical after the Commission issues the order in the next rate case (filed in 2016).
3. Remove the ineligible expenses from the 2010 test year PPCA and include the recoverable costs in the general rate (i.e., include $562,035, all but the lobbying costs, in the general rates).
4. Adopt Staff's specification of the cost components that MEC may include in the purchased power adjustor.

SECTION 4: THIRD PARTY POWER SALES

Q. Do you agree with Mr. Stover's conclusions regarding the two alternatives for allocating the margins from third party sales?

A. No. Mr. Stover reasonably describes the alternatives and even their respective benefits. However, he reaches the conclusion that it is more equitable and preferable to flow the margins on the sales to net income. Staff believes it is preferable to flow the margins on third party sales to offset purchased power costs to reduce the PPCA rate and/or reduce the purchased power bank balance (credit the ratepayers).

Q. What advantages does Mr. Stover cite for flowing the margins to net income?

A. Mr. Stover cites the benefits under MEC's method as resulting in higher coverage ratios, increasing the equity ratio for MEC and increasing the equity of each member in the Cooperative (Rebuttal page 24, line 8).

Q. Do you agree that these alleged benefits warrant rejecting Staff's proposal to flow the margins to offset purchased power costs?

A. No. Each of the benefits cited by Mr. Stover comes at a cost – namely that the Cooperative has more money which comes at the expense of its customers. This is not "free money" that will increase the coverage ratios and equity. It is money that would have otherwise been used to offset ratepayer costs which the ratepayer now must involuntarily "invest" in the Cooperative.

Staff's proposal results in the economic benefits associated with the margin on a third party sale flowing back to customers on a timelier basis. It is not clear when a customer would actually receive a tangible benefit under MEC's proposal. It could be many years or even decades before MEC's capital needs developed such that customers could derive a tangible benefit. That creates intergenerational equity problems for MEC's proposed approach.

Q. Does Mr. Stover also cite inequities as a reason to adopt MEC's approach?

A. Yes. Mr. Stover argues that inequities result under Staff's proposal because the sales occur during low load conditions, and thus would get credited back to customers using power during low load conditions although a large part of MEC's fixed costs are paid during peak periods. (Rebuttal Page 24, line 28)

The fallacy in Mr. Stover's argument is that the customer's rates do not change monthly. They may change periodically if the purchased power bank balance gets excessive. MEC can set its PPCA rates taking into account the size of the bank balance. The bank balance acts as a buffer essentially eliminating Mr. Stover's alleged timing inequities. Nonetheless, Staff's approach will certainly flow the benefit to ratepayers much more quickly that MEC's proposal.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission adopt Staff's proposal to use the margins from third party sales to offset purchased power costs.

SECTION 5: LIMITS ON SPOT MARKET PURCHASES

Q. Mr. Stover rejects your recommendation that MEC reconsider the arbitrary limit on the amount of spot market power MEC will consider for meeting loads. What is your reaction?

A. Mr. Stover misses the point and clouds the issue by drawing a distinction between a policy and a criterion, and also by introducing an argument that MEC can always offset power from AEPCO if the spot market price is lower.

I referred to it as a policy while Mr. Stover indicated that it is not a policy but a planning criterion which Mohave can change at any time. (Rebuttal page 27, line 9) That distinction is a red herring. The persons in charge of planning are not in a position to change either a criterion or a policy, either will have the same effect. Power supplies relying on more than the small arbitrary limit imposed by the criterion will not be considered. And that may result in increased costs.

Mr. Stover argues that if spot prices are low, MEC can always back down on power taken from AEPCO. The problem with that is that Mr. Stover mixes economy energy with capacity planning. Backing down AEPCO generation if the spot market is cheaper is a classic economy energy approach, minimizing the real time cost of energy (utilizing a set of capacity resources acquired based on long term capacity planning).

However, the criterion in question is for capacity planning, not for economy energy as Mr. Stover suggests. After MEC determines its load forecast, it has several alternatives available to provide the capacity needed to serve the projected loads. The capacity need can be met by AEPCO, block purchases and the spot market. Since the amount of capacity available from AEPCO is fixed, if the reliance on the spot market is arbitrarily limited, that forces MEC's planners to secure block power. A review of Surrebuttal Exhibit JEM-1 CONFIDENTIAL (page 2) and Exhibit JEM-15 CONFIDENTIAL (page 4) shows that from August 2001 through December 2010, the block power contracts were typically higher priced than the spot market. The point is that the criterion setting an arbitrary limit on spot market supplies is related to fulfilling capacity requirements. The reason for the criterion is to ensure that there is not excess risk that spot market prices will increase and cause increases in the cost of service. I would agree with Mr. Stover that spot prices could be higher or lower than block power prices. However, as spot market prices have stabilized, it would be inappropriate to prevent the utilization of spot market resources because of a criterion designed when spot market prices were volatile.

Mr. Stover suggested that AEPCO generation could be curtailed if spot market prices ended up lower than AEPCO production costs. This is not related to capacity or capacity planning. It is economy energy that is dispatched day of or day ahead. It substitutes cheaper spot market power for more expensive power from existing capacity resources. Economic dispatch requires that the market power prices are checked many times daily to determine if an opportunity exists to lower the production cost. The criterion does not apply to this situation. Again, it is a capacity planning rather than an economy energy criterion.

Mr. Stover obfuscates the point by mixing the capacity planning criterion with economy energy dispatch.

Q. Is there any downside to raising the criterion to allow more capacity needs to be served by spot market resources?

A. No. Raising the small arbitrary limit does not require MEC's planners to rely more heavily on the spot market to determine their capacity resources. It only gives them the opportunity to consider more spot market capacity if conditions warrant that. By leaving the limit at its present low level, that forces planners to plan for block power purchases instead of spot market supplies.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission adopt Staff's proposal that MEC reconsider the arbitrary limit on spot market supplies for capacity planning. The Commission should require MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on MEC resource planners.

SECTION 6: FUTURE CASE FILING SCHEDULES AND CONTENT

Q. Mr. Carlson and Mr. Searcy both address Staff's recommendation that the Commission require MEC to file its next rate case by April 1, 2016. Is Staff open to modifying its recommendation?

A. Yes. Staff believes Mr. Searcy makes a valid point in waiting until September 1 in order to get an audited report and would support that modification.

Mr. Carlson offers to meet with Staff to develop a streamlined reporting and review process. That would be reasonable, as long as the necessary information is generated and decisions made regarding prudence, future test year, and other issues. Staff's observation is that this process was unnecessarily prolonged because of difficulties acquiring data. This may have been the result of differing opinions about the purpose of this case. It would go a long way to streamline the case by determining in advance what will be the purpose of the case, including, for example:

- Conduct a prudence review
- Specify the time period
- Set future general rates
- Set future base purchase power cost
- Reconcile, adjust or settle the purchase power bank

Q. Could scheduling the next rate case to occur within five years of the last case simplify and streamline the process?

A. Yes. Having a more frequent rate case would reduce the large volumes of data that had to be reviewed in this docket. By looking at only 5 years rather than 10, it would simplify the review. It would also make it easier to recall or reconstruct the context in which MEC made its power purchases.

If rates are more frequently adjusted, the odds of there being a financial emergency before MEC comes in for a rate case are reduced. If problems with the cost recovery, rate structures, power supply costs, volatile markets, and other things arise, they can be resolved on a more-frequent schedule. If conditions occur that require urgent attention, MEC could file the next rate case less than five years after the last rate case. Under Staff's proposal, the next case would be filed in 2016, but could be filed sooner if needed as long as the test year ends no more than 8 months prior to the filing date.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission:

1. Adopt Staff's modified proposal that MEC file its next rate case on September 1, 2016.
2. Direct Staff and MEC to meet within two months of the order in this case to discuss options for streamlining the rate case process.
3. Identify the nature of the issues and information required for the next case, leaving flexibility to modify the issues as the rate case approaches.

SECTION 7: OTHER ISSUES

Q. Beginning on page 19 of his rebuttal testimony, Mr. Stover discusses the financial implications to MEC resulting from Staff's proposed adjustments to the purchased power bank. Are Mr. Stover's calculations applicable?

A. No. Mr. Stover bases his calculation on a Staff adjustment of $3.1 million. The correct Staff adjustment at this time is $0.7 million, less than one-fourth of the amount used be Mr. Stover. That would dramatically change his calculations.

Q. Please explain.

A. Mr. Stover estimated the total Staff adjustment to be $3,102,802. (Stover rebuttal, page 20, line 11) This consists of adjustments of $1,946,000 for the 2001-2006 prudence penalty, of $594,737 for the 2010 ineligible costs, and of $562,065 (or more) for ineligible costs incurred after 2010. He assumed that the adjustment for ineligible costs incurred after 2010 would be made coincident with all of the adjustments made for costs incurred in the current prudence review period (August 2001 through December 2010).

The current adjustments are much less than what he used. Staff's current adjustments are $91,537 for calculation errors and omissions, and $594,737 for the 2010 ineligible costs. The correct Staff adjustment for this case is $686,274.

The Staff adjustment for ineligible costs included in the PPCA in 2011 and 2012 would not actually occur until all of the purchased power costs were reviewed in the next rate case. Since MEC continues to book ineligible costs for recovery through the PPCA until the order in this case is effective, the final amount is not known at this time. However, as suggested by Mr. Stover, the amount is likely to be similar to the amount MEC incurred in 2010, on the order of $600,000.

Q. Mr. Carlson testified that "increases are sought only when they are necessary to continue to provide reliable electric service, both in the short term and the long term, and/or in order to satisfy financial criteria established by their lenders." (Page 5, line 31) Is this principle borne out by MEC's PPCA and purchased power bank?

A. No, it does not appear to be. I looked at the long term history of MECs PPCA rate versus the average monthly cost. From 2001 to 2006, the rate stayed the same while the average cost was cyclical. The bank balance was correspondingly cyclical near zero. When monthly costs started rising, MEC was slow to adjust its rates, meaning that the bank balance became strongly under-collected, where it remained from roughly June 2006 through December 2008. In 2008, MEC finally substantially raised the PPCA rates and by mid-2009, MEC's bank balance moved into an over-collection mode. It remained in a strong over-collection mode throughout 2010. While MEC dropped its PPCA rates a little, the level of over-collection persisted. So it does not appear that increases are only sought when necessary in that MEC allowed substantial swings in the purchased power bank balance in recent years. Please refer to Surrebuttal Exhibit JEM-5CONFIDENTIAL.

SUMMARY OF STAFF'S RECOMMENDATIONS

Q. Please summarize your recommendations from your Direct Testimony of January 12, 2012 as modified by your Surrebuttal testimony.

A. The following is a list of recommendations made in my Public Direct Testimony, beginning on page 46, as modified to reflect changes resulting from additional information filed by MEC since I filed direct testimony and in response to MEC's rebuttal testimony.

1. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

2. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable. In addition, direct MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on MEC resource planners.

3. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

4. Reaffirm that for purposes of the purchased power adjustor, purchased power shall include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

5. Adopt Staff's specification of cost components which may be included in the fuel and purchased power cost adjustor. The specified cost components shall be limited to RUS Accounts 555, 565, and 447 for purchased power and 501 and 547 if MEC purchases fuel for power generation in the future. These are the same components specified by the Commission in 2005 for AEPCO.

6. Remove $594,737 from the 2010 test year base cost of power those costs ineligible for recovery through the purchased power adjustor that MEC has included as purchased power costs in 2010, namely in-house labor costs, consulting costs, lobbying costs and legal costs associated with planning and procurement of purchased power. Reallocate $562,035 of those costs to revenue requirements for the general rates.

7. Reduce MEC's purchased power bank balance (credit to ratepayers) by $594,737 to adjust for the inclusion of these ineligible costs as soon as practical after the Commission issues its order in this docket.

8. Reduce MEC's purchased power bank balance (credit to ratepayers) by $91,537 to adjust for MEC's errors and omissions in calculating the purchased power cost and bank balance between August 2001 and December 2010, inclusive.

9. Determine that the actual eligible purchased power costs were adequately documented from August 2001 through December 2010.

10. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible costs and errors and omissions, are prudent and reasonable for August 2001 through December 2010.

11. Require MEC to file a rate case with purchased power prudence review no later than September 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapse between this rate case and the next rate case to ensure the purchased power cost data and supporting information remain fresh. The prudence review will cover the period beginning January 2011and ending in December of the test year. MEC may file sooner if necessary, with a test year ending no more than 8 months prior to the filing date.

12. Require MEC to adjust the bank balance in the next prudence review to remove in-house labor costs, consulting costs, lobbying costs and legal costs associated with planning and procurement of purchased power that MEC included in its purchased power adjustor in 2011 and 2012. Although identified as ineligible costs in this rate case (prudence review through 2010), the costs will actually have occurred in the next prudence review period and the adjustments shall be made in that review.

13. Require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided; Staff shall recommend that any undocumented and/or unverified costs be denied including interest or that the purchased power adjustor be eliminated.

14. Require MEC and Staff to meet within two months of this order to discuss options for streamlining the rate case process. Also identify issues and information required for the next case, leaving the flexibility to modify the issues as the case approaches.

15. Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

16. Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

17. Acknowledge that MEC's selection and management of Western Area Power Administration ("Western") to provide critical services are prudent and reasonable.

18. Require MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period.

19. Adopt a base purchased power cost of $0.087701 per kWh.

Q. Does this complete your surrebuttal testimony?

A. Yes.

SURREBUTTAL EXHIBIT JEM-1

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SURREBUTTAL EXHIBIT JEM-2

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Q. What cost components would be included in the adjustor?

A. The cost components would be the costs recorded in RUS Accounts 501 (fuel costs for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 547 (fuel costs for other power generation), 555 (purchased power costs, both demand and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included. Power supply costs directly assignable to special contract customers would not be included in the calculation. Non-Class A sales for resale (RUS Account 447), less revenue for legal expenses, would be credited against the cost components.

Q. How does Staff's proposal differ from AEPCO's proposal regarding the components in the adjustor?

A. Staff proposes to include gas reservation charges, demand charges for purchased power, firm wheeling costs, and non-energy charge revenue from non-Class A sales for resale that AEPCO did not propose to be included in the adjustor.

Q. Why is Staff proposing that those items be included?

A. Gas reservation charges should be included because they are a part of the cost of obtaining natural gas for operating power plants.

Demand charges for purchased power should be included so that the method of cost recovery does not influence decision making when negotiating contracts. Some contracts in the marketplace are structured with only a per kWh energy charge that would include capacity costs. Other contracts are structured so that capacity costs are recovered through a per kW demand charge. AEPCO should negotiate these contracts so that they obtain the best deal for ratepayers. If only energy charges went into the adjustor, the method of cost recovery could influence the resulting structure of the contracts.

Firm wheeling costs should be included in the adjustor because they should be considered when negotiating purchased power and wheeling contracts. If only non-firm wheeling costs were included in the adjustor, the method of cost recovery could influence the type of contract that AEPCO would negotiate.

Including all revenue from non-Class A sales for resale as an offset to costs allows the Class A members to benefit from the margins of those sales. Since Class A members pay for the costs of the resources, it only seems fair that they benefit from the non-Class A sales.

Q. How often would the adjustor rate be reset?

A. The adjustor rate, initially set at zero, would be reset semi-annually on October 1, 2006, and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year. AEPCO would submit a publicly available report, with a revised tariff, that shows the calculation of the new rate on September 1, 2006, and March 1, 2007, and thereafter on September 1 and March 1 of each subsequent year. The adjustor rate would become effective with billings for October and April unless suspended by the Commission.

Q. Are the above dates different from those proposed by AEPCO?

A. Yes. Staff changed the dates to have the new rates go into effect before the winter season and before the summer season, taking into account the probable time for a Commission decision in this case.

Q. Would there be a balancing account?

A. Yes. The dollars associated with the calculation of the adjustor rate would be accumulated in a balancing account.

RUS Account Definitions

555 Purchased Power

A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall also include, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, or capacity. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

Note: The records supporting this account shall provide information pertaining to the purchase of power from renewable energy sources.

565 Transmission of Electricity by Others

This account shall include amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others.

447 Sales for Resale

A. This account shall include the net billing for electricity supplied to other electric utilities or to public authorities for resale purposes.

Note: Revenues from electricity supplied to other utilities for use by them and not for distribution, shall be included in Account 442, Commercial and Industrial Sales, unless supplied under the same contracts as and not readily separable from revenues includible in this account.

B. Account 447 shall be subaccounted as follows:

447.1 Sales for Resale—RUS Borrowers

447.2 Sales for Resale—Other

447.1 Sales for Resale—RUS Borrowers

A. This account shall include the net billing for electricity supplied to RUS borrowers for resale.

B. Records shall be maintained so as to show the quantity of electricity sold and the revenue received from each customer.

Note: Revenues from electricity supplied to other utilities for use by them and not for distribution, shall be included in Account 442, Commercial and Industrial Sales, unless supplied under the same contract as and not readily separable from revenues includible in this account.

447.2 Sales for Resale—Other

A. This account shall include the net billing for electricity supplied for resale to utilities not financed by RUS.

B. Records shall be maintained so as to show the quantity of electricity sold and the revenue received from each customer.

Note: Revenues from electricity supplied to other utilities for use by them and not for distribution, shall be included in Account 442, Commercial and Industrial Sales, unless supplied under the same contract as and not readily separable from revenues includible in this account.

SURREBUTTAL EXHIBIT JEM-5

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Jerry Mendl

From: Pierce, Dorothy [dorothy.pierce@chguernsey.com]
Sent: Wednesday, March 07, 2012 4:10 PM
To: Jerry Mendl
Cc: William Sullivan; Candrea Allen; Bridget Humphrey; Michael Curtis
Subject: Missing invoices 2001 - 2006

Jerry,

We know your time is short and Mohave and I have located all documents you have requested for the entire 9 ½ year period involved in your audit of Mohave's power purchases with the exception of:

- 6 AES transactions in 2002 (involving July 2002 purchases of $134,475 and credits over the months of August through December 2002 of $964,961 – resulting in a net credit to the fuel bank balance of $830,486);
    - On June 3, 2005, Commission Staff was advised that during the first six months of operations AES members did not exchange invoices. See, JEM 13.1, 2002 Confidential, page 36 of 51. These are the same months for which you are requesting documentation.
- a $318.96 credit to the fuel bank balance in April of 2004.
    - While the statement is likely misfiled and locatable eventually, we cannot justify searching further for this single invoice.

Thank you for working with Mohave and me on this effort.

Dorothy

Dorothy Pierce
Senior Consultant

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